COMMITTEE WORKSHOP

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

In the Matter of:	
Preparation of the 2005 Integrated Energy Policy Report (Energy Report)	Docket No. 04-IEP-01
Re: Corridor and Strategic Transmission Planning Issues	

CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

THURSDAY, MAY 19, 2005

9:38 A.M.

Reported by:
Christopher Loverro
Contract No. 150-04-002

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

Jackalyne Pfannenstiel

STAFF PRESENT

Melissa Jones, Advisor

Mike Smith, Advisor

Jim Bartridge

Judy Grau

ALSO PRESENT

Laura McDonald
San Diego Gas and Electric Company

Don Haines
San Diego Gas and Electric Company

Chifong Thomas
Pacific Gas and Electric Company

Jorge Chacon
Southern California Edison Company

Duane Marti
U.S. Bureau of Land Management

Susan Lee
Aspen Environmental

Yvonne Hunter
League of California Cities

Richard Rayburn
California State Parks

Buck Jones
Pacific Gas and Electric Company

ALSO PRESENT

Joe Eto
Consortium for Electric Reliability Technology Solutions
Lawrence Berkeley National Laboratory

R. Peter Mackin
Navigant Consulting, Inc.

Eric Toolson
Pinnacle Consulting, LLC

Gayatri Schilberg
JBS Energy, Inc.
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California Public Utilities Commission

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Jeff Harris, Attorney
representing 3M Corporation

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P R O C E E D I N G S

9:38 a.m.

PRESIDING MEMBER GEESMAN: Good morning. Thank you for being here. This is a workshop of the California Energy Commission Integrated Energy Policy Report Committee. I'm John Geesman, the Commission's Presiding Member of that Committee.

To my left is Commissioner Jim Boyd, the Associate Member of the Committee. To his left is Mike Smith, his Staff Advisor. To my right is Melissa Jones, my Staff Advisor.

This is a topic we've visited many times over the course of the last year. I think we'll visit it many times again over the course of the next year. But we hope today to begin to put some meat on the bones of the concept of transmission corridor planning.

I think, as everyone knows, this is a matter being taken up by the Legislature this year. I expect that will be the real forum in which any meaningful change occurs. But this workshop is important to try to better develop an understanding of the views of different stakeholders, give our staff an opportunity to digest those views and reflect on them.

And at some point in the fall Commissioner Boyd and I will issue a Committee report to the full Commission that will then be taken up as the Commission's strategic transmission plan.

That remains a somewhat amorphous concept because we haven't yet determined exactly what will best serve the state's interests going forward. And we want to carefully integrate our efforts both with actions pending in the Legislature, with the Governor's proposed reorganization plan, and with the Public Utilities Commission's procurement process. So it's a work in progress. We're probably best off getting started on it immediately.

Commissioner Boyd.

COMMISSIONER BOYD: I couldn't possibly do a better introduction; and I'm not even going to attempt to best Judy on the comedy of the morning. So, let's move on.

PRESIDING MEMBER GEESMAN: Jim.

MR. BARTRIDGE: Okay. Good morning. This is a two-part workshop. Part one is focusing on transmission corridors as part of the strategic grid plan. It culminates with a panel discussion regarding the state-led corridor planning process.

Part two focuses on strategic transmission planning. I'll leave that for Judy.

Next slide, please. Okay. The 2004 Energy Report update noted that California lacks a seamless process for moving transmission projects from planning into permitting, and recommended the development of a planning process that recognizes strategic benefits and the long life of transmission projects, as well as the development of a state-led process for transmission corridor planning.

So, what we're attempting to develop is a transmission planning process that addresses many issues including physical and economic need, as well as environmental and land use issues. A vital component of that process is the identification and assessment of transmission corridor needs.

Next slide, please. The Commissioner already alluded to this as well, but what's new this year. Senate Bill 1565 added a section to the Public Resources Code requiring the Commission to submit a strategic transmission plan to the Legislature by November 1st.

Now these other two are proposed and under consideration at this point. The first is proposed legislation 1059 would authorize the Commission to designate transmission corridors; and the proposed energy agency reorganization plan, which would, among other things, transfer transmission permitting to the Commission, which would remedy the lack of a seamless process noted in the last slide.

However, regardless of the outcome we would still be working on transmission infrastructure assessments and a strategic grid plan, which is the focus of our presentations and panel discussion today.

From there we'll go right into the presentations. I'll turn it over to Laura McDonald with SDG&E and Don Haines, as well.

MS. McDONALD: Thank you very much, Jim. Thank you for the opportunity to give our presentation here today on my favorite subject which is San Diego Gas and Electric's new proposed 500 kV transmission line.

I am the Project Manager for that project. Yesterday we had an opportunity in San Diego to also talk about the project. And what I wanted to do very quickly was just kind of introduce the project, and then really turn it over to Don who's going to speak more specifically to the transmission corridor issues.

But we do have a project on the books. San Diego right now, and I guess -- sorry, next -- right now San Diego Gas and Electric in our service territory we have one 500 kV line which we refer to as the SWPL, the southwest power link. It was built in the '80s. And we have, following our Valley Rainbow project, which, of course, was denied by the Public Utilities Commission two years ago, have since come forward with our new project.

We have a reliability issue deficiency that would make this line, the in-service date for this line necessary in about 2010. In addition to reliability benefits, we're looking at this project as kind of a three-pronged approach, which is reliability, access to renewables, and economics.

And here's our famous stool that we've been using. But this is really, they're the drivers for this project. And as we come forward with our need assessment on this project, it really will be based on these three prime objectives for us.

We have completed our feasibility study through the STEP process. We're excited now that we actually have a point A to point B for our project, which is an eastern interconnect, which really does follow very closely with our long-term resource plan and the need for this project.

We worked closely with the CEC, the PUC, the ISO through the STEP process and had a lot of input on the project. And I'll go through -- the technical studies are available and I'm sure a lot of people here are familiar with them.

And just kind of how the STEP process worked for us, we had 22 participants on our technical working group. We made several presentations; it was a very open and public process for us.

And really, the technical study just looked at technical performance. It's kind of an issue in San Diego right now. I think some folks feel like the route has already been selected for our project. And we want to make sure everybody understands that from just a technical standpoint we know that we need to go from the Imperial

Valley into San Diego and then possibly north. And how we get there and the routing is something that we will enter into in our next phase of the project.

We did look at 18 alternatives through the technical working group. We weren't able to narrow it down to four that we're looking at. But our preferred alternative is the eastern interconnect at this point.

And kind of our next steps; we'll issue the final study by the end of this month. We're continuing our technical studies looking, obviously, to the ISO Board for approval of the preferred alternative. And then we will launch immediately into our routing studies and the environmental analysis. We should have a contractor on board by the end of next week evaluating the firms.

And then really I think what's important to us is a complete stakeholder process as we move forward on the routing, which would include local elected officials, the environmental community, the federal and state agencies, local agencies. And I think that's what's important, is we can't get through the routing for this project without having all stakeholders involved.

And then just some of our challenges. Obviously everybody here knows what those are. It takes, you know, five years to plan and permit a transmission line today. You know, had Valley Rainbow been approved, we would be very much in the stages of having that line almost completed.

We have multiple governmental agencies, whether local, state, federal. Unfortunately, as you'll probably hear today, many don't work well together. And we have duplicate processes that just doesn't -- they certainly don't make sense at this point.

Community impacts, and then the lack of available land. And I think, if I can pull that up at some point. Again working together stakeholder process. In kind of the statewide support, I think the CEC's involvement in this and helping us kind of get through this process has been important.

The ISO and the PUC, I think, all will come together and figure out how to make kind of the transmission corridors, or in our case, maybe more a route, an important part of this process.

What wasn't on here and I just wanted to show, it's kind of hard to see here, but from a visual standpoint this is our service territory. And this is kind of what we're up against in San Diego in trying to get a transmission line.

We have the Anza-Borrego State Park. We have federal land, state lands, tribal lands. And so these are many of the challenges as everybody goes forward in looking at transmission corridors.

So, thank you very much. I'll turn it over to Don Haines.

COMMISSIONER BOYD: May I ask you a question?

MS. McDONALD: Yes.

COMMISSIONER BOYD: You said it takes five years in this day and age. Can you give me a professional guesstimate of how long you think it should take, if everything worked well?

MS. McDONALD: Well, I think we are looking at trying to, in this case, I think, I've been given the challenge in the company to try and make this a three-year process if we can.

And I think what you'll see in this energy reorganization and these agencies coming together is how do you streamline the process, especially the environmental process. And instead of having, you know, an environmental -- you know, we do our environmental study, and then the PUC does their environmental study. Is there a way that we could, in fact, do one environmental study in conjunction and try and streamline the process there.

And then I think from an agency standpoint, working with the federal agencies and the state agencies, I think it can be streamlined. And we've been given the challenge, as the project team in San Diego, to find a way, maybe even in the CPCN process, if that's the process we go through, to maybe bifurcate the need assessment from the environmental assessment. And try and get a need finding sooner, and then be able to work through the environmental issues.

So I think we're trying to figure out if we can do this in three years versus five years.

COMMISSIONER BOYD: Thank you.

MS. McDONALD: Thank you.

MR. HAINES: Good morning; a pleasure to be here. My name is Don Haines and I'm the Manager of a group we call land planning and natural resources. And it's my team's major effort to do site research and route research looking for the least objectionable route from all perspectives.

And so what I'm going to talk about today, and you can go to the next slide, is how we have interfaced with the local land use agencies, and whether they're jurisdictions or agencies. And what the result was -- and this is, I'll make a few generalizations.

It's based on something that happened two years ago when we knew that if we could perhaps facilitate our efforts if we could get into the general plans of local land use agencies.

First of all, I'd like to say that we do recognize at SDG&E the absolute importance of an overriding state effort to site transmission lines. We've found it very difficult in our own county to do that from our perspective. And I'll get into that later.

We support 1059. But we also would like to, at the same time that we support this process, we'd like to caution everybody that our experience has demonstrated, and I'll do that in a few minutes, that there really is not very much information in the general public and at the local level about what requirements are needed for transmission lines. And that the conflicts that naturally arise through land use, through agencies and the public and private ownerships create a lot of land use issues.

And we think that certainly we should start at a state and large regional level. And we also think, at the same time, not only should we try to accomplish some particular corridor, but we also have to enter into an educational program. Unfortunately I see so much conflict in this arena that I predict that it might be 20 years before we can actually get people to understand the importance of these issues.

Next. Two years ago -- and these conclusions are based on something that we did about two years, actually a little bit longer. We decided that we needed to work with the local agencies and try to get them to understand our need.

And so we requested meetings with all of the 17 jurisdictions in San Diego County, and the County of San Diego and SANDAG. The response was that SANDAG, the County and three cities said, well, we'll talk to you. The other 14 jurisdictions weren't really interested.

Now, you realize that in general plans that -- I've not really seen an energy element. There may be some general plan somewhere in the State of California where there is an energy element, but in general they don't exist, although they're discussed.

So what we did was we threw out the idea that okay, we won't ask for you to put in a whole new element into your general plan, because that was just out of the question. What we did say was well, perhaps we could introduce a conceptual energy as land use in your land use section. And all general plans have a land use section.

What we did was then prepare language. And I have about 40 copies, if anybody's interested. We actually produced a two-page language that we suggested would go into a land use section. And we made this presentation at the, as I say, SANDAG, County and three cities.

And the policies addressed not only transmission lines, but substations and any other facilities that might be associated with transmission.

Next one. So the result was a very polite and respectful thank you. And we have gone through a lot of work. And you can still hear a little bit of bitterness in my voice today. But there really wasn't much interest.

But I think there's an important lesson to be learned in this experience. And that was that as the local agencies go through their general plan updates they're faced with a lot of issues. And we realize that. And so, for example, the County of San Diego has been in their 2020 for 50 years. Not that long. But a long time.

So, what our conclusion was is this statement at the bottom of this slide, accommodating energy infrastructure in a modern development setting takes unprecedented cooperation among competing interests.

Next slide. I think that we can expect extremely contentious behavior with all of the interested parties. And so I do think that it is proper and right to start at the top and set aside broad-range goals. But all of the contentious fighting will occur on a local level. We can expect that, and we need to prepare for that.

How do we do that? I think we have to engage in a very powerful education program. And that program has to talk about how infrastructure works. I think the general citizenry does not understand the electric grid, and they don't understand how power moved from one place to another.

One of the things that we need to recognize, and this might open us up for some possible legislative action, is that agencies are not required to include energy in their comprehensive planning documents. I think this is a problem and I think one thing that we could do would be to try to see what we could accomplish on a state level to force agencies to include this.

The result of not having to include this, and I grew up in this field long ago when I came into the planning, one of the first things that we did was for any project was to go through a local agency and then ask, say SDG&E, a will-serve letter. And the letter said: will you serve this project. And, of course, no one knew at the agency that SDG&E was obligated to serve. They didn't even need to ask that question. And that was the total CEQA response, you know. Could you serve? Yeah, we could. Okay, no problem. It didn't say anything about where you would locate anything.

Current planning leaves really no room for this, and you can, as you get into a local situation, even if the agency is very aware and they require the developer to include a site for a substation, they very very rarely do they provide for access to that substation. And they don't think about whether that substation is close to a transmission line or not, and whether it needs a transmission line.

Therefore we conclude we've got to do something at the statewide or even the national level. And there needs to be a lot of cooperation among all of the local agencies. And I don't have any suggestion on how that will work.

I think that your proposed transmission approach is very critical and important. I think that it will raise awareness within the state. I think that's important. And I can't say enough that there has to be a lot of education along with the raised awareness. Don't just make suggestions, but educate people about why these things are important.

I'd just like to point out a couple of things that I think are important, that the public really doesn't understand in transmission planning.

One is the overhead versus the underground issue. All cities have, as a grand desire now, to put all transmission underground. That's a major issue, especially when you look at a 500 kV line.

Another issue is in a county like San Diego, and I know that's not necessarily typical of California, all of your development is on the western side of the County. We have the largest number of Indian tribes in the country are located in San Diego County. We have many federal land managers, such as the BLM and the Forest Service. And we have military bases.

All of these people have to come together with 17 separate local jurisdictions. And where are you going to put renewables? Well, they're going to be out in east County and there's got to be a way to get this stuff onto the line to where the population is. Hence, transmission. People do not understand that.

Another thing is that in moving electricity, of course, size makes a difference. That's, I think, a concept that people have to understand.

And I think also the importance of generation diversity. And you know all these issues, but they have to -- this is part of the education program that needs to go on at the same time that we talk about transmission.

So, to summarize, we fully support the transmission planning process. I hope that this local example, and I'd be glad to talk at a later time about how we've worked with State Parks and the Forest Service, as well as Indian tribes, as well as the 17 jurisdictions, but this is just one example of how difficult it will be to site the transmission corridor.

I think that we have to raise the consciousness of this country, as a matter of fact, that transmission lines are like a freeway. And even though people do not like freeways going through their community, eventually they understand that they might have to. I don't think that awareness is at that level for transmission.

And as I've said over and over I think that for this to be successful we have to educate.

That's a little plug. So, thank you very much. And, as I say, I look forward to later in the presentations that I talk about our unique experience. And I do have this handout of the -- it's just two pages -- of what might fit into a land use plan. Thank you.

MR. BARTRIDGE: Thank you, Don and Laura. Our next speaker will be Chifong Thomas from --

MR. SMITH: Jim, before you go on to the next speaker, one quick question to clarify something that Don raised about general -- energy elements in general plans.

Could you clarify the current legal requirement for energy elements in general plans? Are they required and they're just not --

MR. HAINES: No, they are not.

MR. SMITH: Okay.

MR. HAINES: They are recommended, but they're not required. There's, I think, seven elements --

UNIDENTIFIED SPEAKER: They're not even recommended.

MR. HAINES: Oh, they're not even recommended --

UNIDENTIFIED SPEAKER: They're an optional element.

MR. HAINES: There is a --

MR. BARTRIDGE: Would you speak into the microphone, please.

MR. HAINES: Oh, sorry. There is a discussion of energy in the transportation element. It's a very vague reference and it might be something that we could explore. But other than that, no, they're not required.

COMMISSIONER BOYD: It's probably energy to move transportation along, not the rest of it.

MR. HAINES: You know, I think that historically energy primarily from a local jurisdiction point of view has always been about conservation and not about infrastructure. So, you know, it advocates buildings that are energy efficient, et cetera, and rewards for that type of behavior.

But, it doesn't really discuss infrastructure.

COMMISSIONER BOYD: I must admit I came away from your presentation with three impressions. As some of you know, Commissioner Geesman and I were in the enlightened community of San Diego yesterday, at least I thought it was enlightened till your presentation.

Having a hearing on a different subject, and it just seemed to me we are of the opinion that the San Diego area is a little more enlightened, SANDAG, your energy people, this, that and the other.

But I guess the other thing I came away with is long ago people discovered the beauty of living in the San Diego area, thus you got all the native Americans and the military bases and what-have-you, so you have a significant issue.

And thirdly, you share my pessimism, I guess I'm a planner, I didn't know that, but with regard to the ability to bring people together to solve problems. I know Commissioner Geesman is sick and tired of hearing me talk about my favorite analogy of how hard it is to lure everybody out of their tribal cave out around the bonfire to try to make progress. And that works for governments, business, et cetera, et cetera.

But, you're right, it's a big task. And the point about the energy element in general plans is a very interesting factoid that we've obviously made note of up here. Thanks.

MR. BARTRIDGE: Thank you, Commissioner. Okay, Chifong.

MS. THOMAS: Good morning; it's a pleasure to be here. Today I'll be talking about PG&E's area conceptual transmission plan for importing Tehachapi generation. And this is based on Tehachapi collaborative study group report which was filed with the CPUC on March 16th.

And as you know, the CPUC had, in decision 04-06-010, ordered a formation of the Tehachapi collaborative study group. And that group consists of the CPUC Staff, the CEC representative, Southern California Edison -- I see that Jorge Chacon is there to keep me honest -- PG&E, the California ISO, wind developers, CEERT and a whole host of stakeholders including the military.

The report was filed, as I said, by Edison on March 16th. And the discussion is on the -- this discussion today is only on the technical aspects, and is only for PG&E areas.

The topic is basically covered in the, you know, along the transmission conceptual plans, and then need further studies.

One thing that you will notice is that this is -- when San Diego was talking about they know exactly which project they're going to build and how they're going to route it, and the difficulties of routing it. And this is actually going one step before that. This is how do we decide which transmission line to build.

But let's talk about the limitations of this last study that we have just performed. Because of a lack of data and information all we have done was we had done the steady state powerflow analysis, which means that we only look at the system that was under normal and some emergency conditions. We did not look at transient and we did not look at voltage stability and a whole host of other analyses that must be done for a transmission planning study.

And so consequently all potential problems or mitigating measures have not been identified.

Here are the major assumptions we made. This is really important because this drives the project, the conclusion as to how big a project, what size project we need to build.

We first assumed 4000 megawatts of generation at Tehachapi area. And we assume all 4000 megawatts will meet the least-cost/best-fit selection criteria for the state. And we further assume that 2000 megawatts, half of it, will flow to PG&E load centers. And then we also assume the conditions that study would be identical to the Cal-ISO control grid studies and the regular transmission planning system impact studies for interconnection generations.

We used basecases that represent 2009 conditions onpeak and offpeak. And we identified, in identifying all the potential problems we follow the regular transmission planning practices that once you add a generator into a system and the load doesn't grow, you've got to decrease generation someplace else. Otherwise we would not have a load and resources balance.

And to do that we displaced generation that was outside the immediate study area. This is for the purpose of identifying problems. Because we displaced a generator that's inside a study area we would not have identified the problem; it will have been masked.

And then the second assumption we're using was that going back to the renewable resources, we are going to displace the generation that were older and more polluting. And then we would run selected outages, which is single and double contingency. And then we go to the, you know, alternative solution and so on.

Anyway, here's a map of the PG&E area. Tehachapi is down around here between Midway and Vincent. And this is Path 26. And Path 26 has a rating of -- a north-to-south rating of 3700 megawatts, and a south-to-north rating of 3000 megawatts.

Path 15 is up here and that has a north-to-south rating of 3265 megawatts, and south-to-north rating of 5400 megawatts. And also notice that Path 26 and Path 15 are in series. So one flow would limit the other one.

As I discussed -- no, no, is fine; next slide, please. I'm sorry. I forgot to give the signal.

What we have is that when we run the cases our cases shows that onpeak we really don't have any problems when you consider the path rating. On Page 26 is the same thing. Once we put in Tehachapi generation the rating, the flow actually goes down from 3400 megawatts down to about 1400, because we are scheduling 2000 megawatts from south -- in a south-to-north direction. And the regular onpeak flow is in the north-to-south direction to supply the southern California load.

Offpeak it's a different story. Notice that on Path 15 we are -- before we add the Tehachapi generation, we are considering at the limit. And once we add it, we actually increase the flow by 2200 megawatts. And this is because in the offpeak the power is flowing from the south-to-north direction, and is the prevalent flow for return energy into the Pacific Northwest.

And down in Path 26 before, in the before case, the Path 26 case was only at 1325 megawatts because the controlling element is Path 15. So that Path 26 cannot load more than 1300 megawatts because otherwise you have overloaded Path 15. So because of that the PG&E study would be concentrating on the offpeak conditions.

Next slide, please. And, again, this is a table showing the, for the curious, the summaries of the flows.

And this is onpeak case. And again we see that the Path 15 went from 5400 to about 7000; and Path 26 went from 1300 to about 3315.

Let's take a look on the line that constitutes the Path 15, north of Midway, that's in the PG&E area. All these red lines shows the overloads. This is an existing problem. Assuming PG&E fixed that, we'd still be looking at eight overloads that need to be fixed by accepting 2000 megawatts. And this does not include, because it's about system study, does not include any underlying system problems. And so the whole idea is figuring how to mitigate this condition.

Next slide. Okay, here's some observations. Again, summer peak we have no problems to accept 2000 megawatts. In the summer offpeak, even before we take any outages we have problems. And so the problem is to be solved.

And so what we need to do is figure out how to solve them. Now, also further the importing additional generation at Path 15 would give you overloads. And the limitation is the existing Path 15 south-to-north transfer capability of 5400 megawatts.

And at this time less than half of Path 26 is being utilized. So, it can be said that if we were to fix Path 15 we could have realized about 1700 more megawatts of flow on Path 26.

So let's see how we solve the problem. For transmission planning study the first thing to do is figure out what you could do without spending any more, or without doing any spending major money.

The status quo. Okay, for the status quo, suppose I were to replace the existing 1300 megawatts on Path 26 with 1300 megawatts of Tehachapi generation. And aside from a FERC open access issue, we have to figure out what to do with the return energy to the Pacific Northwest. It has to go somewhere; the other side of the loop, I suppose. So that had not been studied in this past study we've done.

Suppose with the (inaudible) Tehachapi generation -- I mean the Midway generation with Tehachapi generation, at Midway about 3500 megawatts of generation connecting to the Midway substation; and about 2600 megawatts of them is there to support a remedial action scheme of Path 54.

What would happen is that we suffer an N-2 outages at Path 15, then we would drop 2600 megawatts of generation at Midway in order to keep the flow under the emergency limits.

So if we were to lower the Midway generation it would mean that we'd have to derate

Path 15. And lowering Midway generation would be in the order of 1 megawatt of Midway generation we would have to lower Path 15 by half a megawatt. So therefore, if we drop 2600 megawatts of generation at Midway, then we would have to derate Path 15 by roughly 1300 megawatts.

The rest of the generation at Midway that were the remaining, that was not on the RAS is because they were either QFs, enhanced oil recovery or too small to be participating in the RAS, the remedial action scheme.

Now suppose we replace Midway, the generation, the RAS with -- the remedial action scheme with Tehachapi remedial action scheme, it's a little bit less effective because of location. It's further south from Midway. The existing RAS controller cannot calculate the -- it has to calculate what the next time period of generation would be in order to figure out how much we trip. So that the existing controller cannot do that. So we need to be new controllers.

And also if there were any generators south of Midway that were there to regulate, even intermittent generation, then they would also have to be put on remedial action scheme, also. So after looking at that and the complication of that of not doing anything, we decided that was not the way to go.

So, we need to build something.

The first thing that we did was that this is a diagram. If you look at -- how come it's not working? Well, anyway, the red lines are Edison lines; and the black lines are PG&E lines. And Edison's Big Creek (inaudible) line, which connects to Tehachapi down here somewhere, crosses PG&E's Helms Gregg line. So if we were to put in a substation here, and then put in a phase shifter which controls the flow, and push about 300 megawatts into the PG&E system, especially during offpeak conditions, this would solve, at least allow PG&E to take 300 megawatts of Tehachapi generation.

That's going to cost about $50 million for the substation and some related equipment. Edison's estimate for that at the time was $50 million, but they have not done a complete study. So the cost could be higher. This would be the subject of further studies, of course.

Alternative 4 that we look at -- oh, I forgot to -- I'm sorry, go back. We also look at doing the same thing at Magunden substation. And that turn out to be not very workable because we couldn't even get 300 megawatts in there without causing more overloads deeper into the PG&E system. So that was abandoned.

Alternative 4, we would build a line from Tesla to Los Ba¤os, down to Midway; and then from Midway to Tehachapi. Remember -- this is a 500 kV line. Remembering that we could, if we were to fix north of Midway, then we could get more out of south of Midway, so we're really looking for another 300 megawatts.

And so one of the idea was that if we were able to use some remedial action scheme here, maybe we can avoid building another 500 kV line, which is about 95 miles between Midway and Tehachapi. But, again, any remedial action scheme on the 500 kV system would have to be approved by WECC. And so far we have not done enough study to even approach WECC for approval yet.

And so if this RAS is workable then it would be about $700 million. And if it's not workable it's going to look like about a billion for PG&E only.

The last alternative to look at was to

build a line between Tesla to Gregg; put in a 500 kV substation here which connects to Helms. And then go from Gregg to Tehachapi. And this is going to cost about a billion.

Again, in our new studies we will be thinking about maybe terminating this line at Midway. And there again see if we can get rid of this one section with the use of a RAS. And if that works we'll save some money for the ratepayers.

And here's a diagram that shows all the alternatives. And here is a table -- I'm sorry, next slide, please, I forgot. Here's a table that shows the different stages that we could stage to figure out how much we can take of Tehachapi generation for PG&E.

Here's some further study we need to look at. We actually, we had started looking into that already. You know, how would -- all the study would have done, so far we did not have a detailed model of the Tehachapi collector system. So we don't know how that's going to -- if we put in a more detailed model, how would that impact the stability performance of the system.

The idea is that -- our inclination is

it is -- suspicion is that it will. Because based on our past studies that anytime you put in something more detailed you will impact -- have some impact on the system performance.

Then the other thing is how would Tehachapi generation impact the operations, because it's a large amount of intermittent energy that flows into the system under offpeak conditions.

Another question is that suppose we put in a Fresno-Big Creek tie and at the time we look at 300 megawatts and it looks like it was okay. But the question then becomes, well, if a little is very good, would a lot be better. So we don't know. And Edison and PG&E will have to do some studies to figure out what upgrade there is in the future studies.

The Tesla-Los Ba¤os-Midway-Tehachapi line, well, there's alternative 4, can we use RAS to avoid building the Midway-Tehachapi section. If we could then -- or we can defer that until another stage where we definitively need to know that we need it.

The other part was the Tesla-Los Ba¤os-Gregg-Tehachapi line. If we terminate at Midway do we need to go all the way to Tehachapi. Well, there are technical issues that we haven't looked at.

So the other questions. These projects are resource driven. So going back to the assumption that we had said before, this is needed if we have 4000 megawatts at Tehachapi; and this would be needed if 2000 megawatts were coming to PG&E.

Now, whether or not -- that was just an assumption because we have no idea how much is coming to PG&E and how much power would flow. So that another uncertainty is the fact that we don't know when the Tehachapi generation will be fully developed. Because right now there are 4000 megawatts, as far as I know, is a technical potential. And we do not know when it would be committed and would be developed.

And then another further question would be that what is Tehachapi in the -- what percentage of Tehachapi is going to be in the state's resource mix of the least-cost/best-fit renewables, because if we are to look at other areas, you know, will we be realizing 4000 megawatts at Tehachapi by 2010. And that is an issue that we need to get some definitive answer on. I think the CEC studies would give us a lot of information on that and help us decide what kind of -- which transmission line should be built and the priority.

And then on top of that we need to look at impact on other transmission resources that's being developed in WECC. We heard about the Frontier line. If it's terminating at Table Mountain we could be leading at a whole different set of transmission. If it's terminated in southern California there's a different issue.

The Northern Lights project that goes from Alberta down to also try to sell power to California, and then there are lines that go to Arizona.

So there are a lot of issues. And all these transmission projects are resource-driven. And so what we need to also figure out is what kind of resource are we looking at. If, for the same amount of energy, if Tehachapi were solar we would certainly need much fewer transmission because solar is onpeak, and we say that we would be able to take a lot of energy onpeak -- a lot of capacity onpeak.

If Tehachapi were geothermal then based on the capacity factor of geothermal energy versus green energy, the total capacity required, transmission capacity required out of Tehachapi would probably be somewhere around 1500 to 1600 megawatts. Which means if half of that would go to PG&E we'd only be looking at transmission capacity addition of about 700 to 800 megawatts.

So a lot of this need to be decided. And there are problems that can be solved. And we just need to know what problem we're solving.

Questions.

MR. BARTRIDGE: Thank you very much. Our next presentation is Southern California Edison; Jorge Chacon will be giving this.

MR. CHACON: Thank you. Good morning; my name is Jorge Chacon; I'm with Southern California Edison, transmission planning department.

Today I'm going to be giving a brief presentation discussing the transmission corridor planning, some of the things that we believe are important.

Next slide, please. The presentation overview is basically four bullets. I'll be talking about the principles for transmission corridor planning process. Will be discussing the land use implications related to electric facilities planning; potential drivers of additional transmission corridors; and some of the potential benefits from corridor planning.

Next slide. As far as the principle for a transmission corridor planning process, Edison believes that corridor designations should be based on long-term planning horizon. We are looking at 10 to 20 years. We think that if you can justify a corridor, you shouldn't be done on a short-term five-year basis, and then, you know, change our mind and identify another corridor. We believe that we want the corridor to withstand the duration of time so that it allows us the flexibility of using it when we do, in fact, need it.

Corridor designation process should include broad participation, including local governments. You heard from San Diego Gas and Electric the difficulties associated with working with the various entities within the local jurisdictions. Edison also believes that that's going to be a difficulty in our service territory, and probably will be so in PG&E's service territory.

State-designated corridors should be compatible with federal designated corridors. We don't believe we should be reinventing the wheels; we believe that what we identify as a corridor should be compatible with what federal agencies also identify as corridors. So we should be working mutually together to facilitate the process.

The cost recovery for land acquisition and designated corridors should be provided. It would be difficult for anybody to go out and purchase land without assurance that they're going to get the money back from their investment. So that is an important topic, an important bullet.

The user of designated corridors should allow expedited permitting for specific project infrastructure siting. We think that the whole reason of doing corridor planning is to facilitate the process of building new infrastructure when the need arises. So, as San Diego indicated, you know, they would ideally like three years. The process right now takes five. What the right number is we don't know, but certainly something shorter than five years would be something that we should be looking at. And we can do that as far as expediting the permitting process.

And last, we should preserve corridor access where there are limited geographical options. Sometimes as encroachment happens to our right-of-ways, we get boxed out of using the right-of-way. So we need to make sure that whenever we specify a corridor that the availability to get to the corridor and use it effectively isn't diminished by encroachment of either housing development or industrial development or other type of development.

Some of the land use implications related to electric facility planning. Land requirements for new facilities. You know, the land, itself, how much land do you need to set aside. That's determined on substation design, you know, how big is the substation going to be; what's the projected load; the right-of-way requirements. And those are driven by how many different transmission facilities you plan eventually to put within the right-of-way.

Whether it's simply high voltage. Whether you're looking at multiple use corridors, such as, you know, water and gas and other utilities within the right-of-way.

And from an electrical perspective, the pole and tower designs. If you go with the pole design then you would need less right-of-way because it's more compact. Standard lattice tower designs, by their very nature, are a little bit wider and therefore require more right-of-way. So the design specifications would be important as to identifying what the right right-of-way width would be.

Land ownership issues. You know there's many different ways to acquire rights, you know. You can go for fee simple, easement or franchise. Those are issues that we believe are going to crop up that we will need to resolve and figure out how these corridors are going to be owned.

Compensation and development restrictions. You know, once you put a corridor you, in effect, restrict certain development from happening. So, you know, there's going to be issues there that are going to have to be addressed.

Electrical system repair and maintenance. San Diego Gas and Electric pointed out that even today they're having difficulties maintaining and repairing their current infrastructure because of getting to the particular corridor, getting to the facilities. We want to make sure that those restrictions are minimized to the extent possible so that, you know, the repair and the maintenance of the facilities can be done expeditiously.

The construction and placement of new facilities would be important to the land use implications. You know, where exactly within the right-of-way do you intend to put the tower. And that's a little bit more nebulous, because, you know, until you design the actual facility you don't know exactly what the placement of the tower would be. But we believe it would be critical to try and at least lay certain principles out for that so that we can look forward.

And last, the land use classification adjacent to electric facilities. For local jurisdictions that's important, whether the land use implications, when you get a new corridor, whether they're -- it's going to remain residential, or are you going to be converting to maybe industrial, or what the local jurisdictions are going to be looking at as far as classifying the lands that are not the corridor, but adjacent to the corridor.

Some of the potential drivers for additional transmission corridors. We actually have a chair as opposed to a stool, as PG&E had. We believe load growth is one of them; new renewable resources. You can roll that in with new generation development, but because of the mandates we felt that that required its own bullet item.

The new generation development is those generation resources that are not renewable, that are pursuing through the FERC mandated interconnection process.

And the last bullet is increased power imports. And there's many reasons for increasing the power imports, whether it's, you know, the desire to bring out-of-state renewables to instate. The desire to eliminate congestion on certain established WECC paths. Or the desire to serve growing load demand from outside resources that are not renewable, but rather conventional.

My last two slides are talking a little bit about the potential benefits from corridor planning. We believe that, you know, in developing a corridor planning process that, in and of itself, will establish formal communication channels regarding the role of future infrastructure needs in community development.

Right now, as has been discussed, there isn't a formal process; there isn't something that, you know, will allow the local jurisdictions to look at the process and say, okay, I need to make sure that enough land is set aside for my electric use needs. So we believe that corridor planning will, at least initiate the process.

It will help identify the proper placements of infrastructure within the local jurisdiction, not within the right-of-way, itself, but within the local area that you're analyzing.

It will establish the context for future facility planning. Will establish the context for future public involvement. Will minimize future siting conflicts, which is an all too common theme when you plan a new transmission facility.

Identify and preserve limited infrastructure access. It will provide an orderly consolidation of infrastructure needs for the multiple utilities, whether it be electric, water, sewage, gas.

And the second bullet is we believe this will give a proactive general planning and environmental review process. Right now we're sort of reactive, you know. We identify a need, and then we react to the need. We initiate the environmental assessments; we file the CPCNs. So it's all a reactive need, and hence that's why it takes, you know, five years minimum to permit and construct a transmission line.

We believe that with corridor planning what will end up happening is effective utility participation within the local planning process. It will provide an improvement to utility review and comment procedures on third-party EIRs. You have local jurisdictions that are doing master community plans for which, you know, from a utility perspective we can be participating in.

Will allow for community general plan update and regional master plans as I just indicated.

It will afford the opportunity for the local planners within the local jurisdictions to get familiar with the utility transmission and distribution plans. Something that probably currently doesn't happen to the extent that it should.

And lastly, it will encourage the inclusion of utility transmission and distribution plans into local land use plans. And that, in and of itself, I think, will go a long way into facilitating future development of transmission facilities.

PRESIDING MEMBER GEESMAN: Jorge, how would you prompt the proactive general planning at the local level?

MR. CHACON: Well, you know, within Edison I think we try to currently engage the local jurisdictions as early as possible within the process. I think if we can establish a mechanism to identify the triggering need even earlier, that, in and of itself, would allow you to engage the local jurisdictions sooner.

So, you know, looking longer term, 10 to 20 years, to identify from a conceptual nature like we've done with the renewable transmission reports, you know, I'm going to eventually need a line from point A to point B. And then work with the local jurisdictions to figure out how is it that, you know, where can I put this line from point A to point B so that I can serve my growing needs in the future.

PRESIDING MEMBER GEESMAN: Is that a role the state should play?

MR. CHACON: Yes, I think Edison is in agreement with the concept. So I think the state can help with that. I think the utilities also have a, you know, we have, as San Diego said, some educational process to undertake and educate the local jurisdictions.

PRESIDING MEMBER GEESMAN: Well, I also think that you're, in many instances, a much better ambassador to the local jurisdictions than Sacramento is.

MR. CHACON: Right.

PRESIDING MEMBER GEESMAN: I think you've got ongoing businesses in those jurisdictions that generally enjoy very good relationships with local officials.

MR. CHACON: Absolutely. Sums up the presentation.

PRESIDING MEMBER GEESMAN: Have you had a chance to look at the various drafts of SB-1059?

MR. CHACON: I've perused them; I haven't really delved into them. I know we provided comments to them. I think there's other people from Edison in the audience that can provide a better answer than I can, so --

PRESIDING MEMBER GEESMAN: I'm not certain of that.

MR. CHACON: Well, --

PRESIDING MEMBER GEESMAN: I wanted to encourage you, Manuel, to introduce Jorge to your governmental affairs people. We get a remarkable stream of very reasonable and extremely helpful input from your company in our forum.

And as you'll remember in our 2004 IEPR process, Patricia Arons really spearheaded this area of the staff's thinking in identifying a need for earlier state government planning of transmission corridors. Somehow when then concepts get lost in the ghetto of your governmental affairs department the feedback becomes quite a bit more strident and certainly less reasonable.

But you might introduce them to Jorge, because he's continued that tradition of reasonable and helpful input. I want to thank you very much.

MR. CHACON: Thank you.

MR. BARTRIDGE: Thanks, Jorge. Our next presentation will be Duane Marti with the Bureau of Land Management talking about the federal process.

MR. MARTI: Thank you. I'm Duane Marti from the Bureau of Land Management. I was supposed to be doing this with Bob Hawkins from the Forest Service; we were going to do it jointly. Unfortunately, he's out of town this week, so it fell to me. You're pretty much just going to hear about Forest Service in generalities and I'll use specific examples with BLM.

Next slide. Since January of this year both the Forest Service and BLM have either revised their rules governing land use planning or their handbook. The Forest Service published their brand new rule in the Federal Register in January of this year. It will be available from the webpage for the Federal Register.

BLM just redid our land use planning handbook. We put it out March 22. We put it on our webpage. Unfortunately our webpage is down right now because of security problems.

I understand from our planning people that the paper copies of the handbook are coming out, hopefully this week or next week, and we should be getting some here in California. So, I don't know when our webpage will be back up, but it's a very good handbook.

Next. Now, both the former rules and the new rules and guidelines acknowledge very strongly that rights-of-ways are a legitimate use of the public lands. And in May of 2002 the Bush Administration issued its national energy policy which directed the federal agencies, BLM, Forest Service and others, to encourage the development of both traditional energy and renewable resources on the public lands.

And when we talk traditional we're talking like coal and natural gas, petroleum; renewable will be solar, biomass, wind, hydro and geothermal.

Here in California BLM currently has applications for all types of the renewable energy for projects on the public land. We see -- BLM sees the public lands in California as very important to the state if we're going to meet the renewable portfolio strategy in the timeframe.

Also the national energy policy recognized very clearly the need to upgrade and expand existing transmission infrastructure throughout the country. Also directed the fellow agencies to assist in that project.

Next slide. The federal agencies are very good at planning for the lands that they manage. But, in a sense, we're sort of managing in a vacuum, because once we get outside of the boundary of our lands, we have very little control over the non-federally owned lands.

And as both San Diego and Edison have talked about earlier today, you got this mismatch of the federal or the state, the counties, local and everything else out there. And we all have to work together.

One thing in California that has been really emphasized by my state director is that we will get out and coordinate and cooperate with all the various other people out there. Could be tribal governments, organizations, other fellow agencies, state and local government and agencies, industry groups, relevant companies.

One of the ones that we work an awful lot with is the Western Utility Group who put together the regional corridor study which BLM and Forest Service right now are working with them to do a revision on that.

And then other interested parties, most have been mentioned already, environmental groups, adjacent landowners. And also the Western Governors Association, which has taken a real active role in looking at transmission projects and renewable.

BLM has a liaison to the Western Governors Association, who is located at their headquarters and works directly with them. And anytime we get involved in a project that's going to be more than one state we work back through.

I have to echo what has been said previously by the previous presentations, if we're going to have utility corridors we're going to plan for them, we're going to manage them, we're going to operate them, we're going to maintain them. It has to be a statewide effort.

I think the study groups that are out there now, the Tehachapi one, Imperial Valley are very good. They're excellent starting points and everything. BLM tries to participate to the extent where possible. I think the Imperial Valley people must wonder if we're out there, because it seems like every time they schedule a meeting I have a prior commitment. And I've been missing in action on that one.

Next slide. We're mandated by federal law to manage the lands for multiple use. This ends up causing competing uses in the same area which can affect utility corridors.

Earlier I met with Jim and some of the other people on your staff about two months ago. And we were talking about just various problems. And one I threw out was an area we have checkerboard ownership. And checkerboard is like every other section is owned by the federal government; the other section may be state, may be private, may be something else. So we don't have a big contiguous block of land.

A perfect example of this is along the I-10 corridor east of Palm Springs. It's a checkerboard area out there. You have Interstate 10, you have existing powerlines, you have existing corridors. The owner of the private land that's intermingled with the BLM land has come to us with a proposal. He wants to do either a sale or a land exchange. He wants to consolidate his holdings out there. Because what he wants to do is develop a residential community.

Well, if we were to go and convey the lands out of federal ownership we could do it subject to the third-party rights transmission lines and things like that, we could do federal reservations.

Our biggest concern is what is the reasonable foreseeable consequences of the lands leaving. The developer's going to develop the project; going to sell the homes; he's going to be gone. Five years, ten years down the road XYZ utility comes and says, jeez, we want to put another transmission line out there. We want to do another pipeline or something.

And I think we're going to run into the same problems in that type of situation that Edison and San Diego Gas and Electric earlier in their presentations alluded to. Everyone wants reliable cheap gas and electricity, but they don't want it in their backyard. And this is the problem we keep seeing time and time again.

So, when we're confronted with these type of decisions, should the land leave federal ownership or should they stay, we need state agencies, the Commission, we need the PUC, the ISO, the people that have the expertise, to tell us is this an important corridor. Is this a corridor that we should maintain and keep viable. Or is this one that we don't need.

So we actually need you folks to come in and on our NEPA documents give us comments, yes, that corridor is very important; we want you to keep the land out there.

Going off of what the person from PG&E was talking about, she was talking about we have renewable projects, renewable energy. Right now BLM in California has approximately 40 applications pending for wind energy projects throughout the State of California.

One of the things that we keep looking at is we can build the projects out on public land. We have the wherewithal to go ahead and do that. But is there going to be the transmission lines and the capability to carry that. There, too, that's where we need the Commission and the PUC and the ISO to come weighing in and telling us is this a good idea or not a good idea.

And someone had mentioned, I believe it was Don from San Diego Gas, he was talking about you end up getting different environmental documents. It is the policy of BLM wherever possible when we're doing a project that involves state land, we always try and do a joint environmental document that meets NEPA and CEQA. And we have been doing that for the last five years on transmission lines and gas pipelines. And it's been working very well.

We've been working mainly with the California State Lands Commission. We've got the procedure down. It works very well. And I would really encourage going to joint environmental documents where we can.

Next slide, please. One of the purposes of the workshop was for us to give comments. And some of the comments I would add: Tribal governments and groups must be involved in the process early, actively. Not to do so, we think, is just sheer folly.

Another agency that needs to really be involved is the Department of Defense. Here in California the Navy, the Air Force and the Marines all have military training routes. These are air space corridors that have been authorized by the Federal Aviation Administration. These corridors are controlled and managed by those military agents in accordance with federal law and federal regulation.

And with Secretary Rumsfeld issuing the BRAC report on Monday, I looked at it very carefully and I did not see where any of the major air bases in California were affected. If anything, their mission has grown. So we're going to have even probably more use of these military training routes.

The question is so what, what's important about this. These military training routes are all over California. And anytime we start intruding into that corridor space, and we're talking as low as 50 feet, it's going to need to be evaluated by the military. Is it going to have an effect on their training and their use of that corridor.

If the structure is higher than 200 feet, you have to go and have an evaluation done by the Federal Aviation Administration.

BLM has been actively meeting with the DOD agencies for the last year and a half specifically on wind energy projects. We have a lot of projects down in eastern San Bernardino County, San Diego County, Imperial County and Riverside County that are going to really impact these air corridors. And our next meeting is actually next Thursday down in Riverside.

So we have been talking to them about this. And not only are they interested in wind energy, they're also concerned about transmission lines, communication sites, and if we start getting solar towers. Anything that's sticking up into the sky that could affect their program.

Also, DOD has been very active in meeting with county governments as a way of getting zoning ordinances to control wind energy projects. Kern County has already issued an ordinance and it's in effect. Los Angeles, San Bernardino and Ventura Counties are in the process of doing these.

So what we're getting is we have this multitude of efforts going on out there. You have workshops like this; you have the study groups; you have BLM meeting with the industry; you have BLM meeting with DOD and BLM meeting with everything.

In the El Centro office we have three major 500 kV lines that are being proposed by Imperial Irrigation District, Southern Cal Edison and San Diego Gas and Electric. So there's a lot of effort going on out there.

And I think if we're going to make any sense out of this we have to sort of have some kind of statewide guidance. And I have to echo, I forget which person mentioned it, that we really need to have the states involved. Because we're running into the same problem that they were talking about dealing with the local governance.

For the federal agencies we are now mandated to include corridor planning in our land use plans. So we're actively doing that. And BLM in California is currently revising or doing brand new plans in six of our field offices. And we are very actively looking and seeking information.

So I think I would really encourage we need a statewide effort. And BLM, at least, is very interested in being onboard with that. Thank you for your time.

PRESIDING MEMBER GEESMAN: Thanks very much. Do you coordinate your efforts with the Forest Service or is that a completely separate planning process?

MR. MARTI: Yes, we do. Bob would be the person I would be coordinating with. He's down at their regional office in Vallejo.

PRESIDING MEMBER GEESMAN: Okay. Great. Thank you.

MR. BARTRIDGE: Okay, for our next speaker, Susan Lee from Aspen Environmental Group will be talking about the PIER program's electronic modeling tool that they're working on.

MS. LEE: Thanks, Jim. Again, I'm Susan Lee with Aspen, and I'm really here representing the PIER group today. We are just about to get started on a corridor modeling program that I think feeds really well into all the issues that have been discussed here today in terms of the problems that are faced in transmission corridor planning.

I've been working for the past 10 years or so on transmission projects from the CEQA side, and the biggest challenge that we face here is dealing with alternatives, finding viable alternatives in a state that's growing so quickly; balancing challenging priorities where you're dealing with community values compared with visual resources and biological resources.

So, the tool that we're hoping to develop, I think, is really going to go a long ways towards helping this process move more smoothly.

The objective that this modeling tool -- well, first let me tell you the name, the name we're given it just to keep a nice acronym is the Planning Alternative Corridors for Transmission, or PACT model. So I'll talk about it in those terms.

It's a computer-based program, a web-based tool that is very visual and helps you assess transmission corridors using a combination not just of environmental factors, but also health and safety issues, engineering issues and economics. So you can look at it from the point of view of the utility who's designing a project all the way through the environmental process and dealing with public involvement.

The goal is to identify transmission corridors that really are viable, and in this goal really tracks well with the possibility of working with SB-1059 on pulling together a lot of electronic data that's more and more available throughout the state, being able to identify big picture corridors that really can be useful as we're going through the planning process, which a lot of people have identified this morning as a real challenge.

Next slide. This model has started with SCE, and SCE several years ago recognized the need for accumulating a lot of electronic data in a way to help them plan projects both for substations and for transmission lines. SCE's been using this model over the past couple years. They've done test cases on individual substations. And I'll show you some examples of that in just a minute.

The thing that they've found and I think the real benefit that we'll see from this is that it really allows for teams to work together. A lot of times, you know, these projects are conceived by engineers, as you all know, and then it gets handed over to an environmental group to do the assessment and fine tune the routing. And the more that those two groups can work together, especially in the early planning phases, the more likelihood of success these projects are going to have.

Next slide. These are just a few of the factors and metrics that are included in the model that exists right now. I'm going to run you through a couple of examples of this, but it just gives you a sense of the range of the kinds of factors we can consider.

Next slide. Now, when you get to this one if you have the handout that's a color page, a single color page, you'll be able to read that a little more clearly, because I know that's awfully fine print to see from a distance.

If you look down the left-hand side here there's basically sort of a navigation bar that shows all the options that are available to you as you're working in this model. And you'll see that the major factors that you can look at in here are CEQA factors, which are the environmental issues, including aesthetics and biology, health and safety, including EMF, community relations. And this is something that obviously Edison has tailored for history that they've had with certain communities, but would have to be broadened for our use in more of a statewide effort.

And the engineering concerns that have to be considered when you're building either a substation or a transmission line.

Then the center part of the page here, this part called land use and planning, this is an illustration of just one of the CEQA factors that's listed here on the left-hand side.

It starts out at the top with a paragraph that says basically why do we care about land use issues. What is it here that we need to know. Then it gives you -- this is an example again from a substation site, so it's not a transmission line, but it would work essentially the same way.

It takes the data on existing land uses and compares, based on the land uses, each of these six substation sites against each other. And then in the case of land use, also looks at future land use, which is an especially important factor as you're looking at areas that are growing.

Then on the bottom you can also see the percentage of land use. Within a half mile of each of these substation sites you can see how much of the land is residential, how much is commercial, agricultural. So it gives you a really good snapshot of what you're looking for when you're comparing the two sites.

Then on the other side here this sort of inset box just gives you an example of what else this tool can do. It can just map land use for you. So it can look at the project area that you're looking at. Again on the top is current land use. On the bottom is future land use. So it gives you just a good sense of what's going on in your project area.

This is another one of the specific pages that you can use. And, again, it tiers off of this menu on the side. We're now on the engineering factors.

You can see on this one one of the things that the model does. Again, it's got the introduction in the beginning that explains, you know, what are the engineering issues that we care about, and what things are important. So from an environmentalist point of view you want to understand what the engineers are concerned about.

This one lets you see a little bit of how the model can set priorities. And on this one you see there are five factors under constructibility that include, you know, slope and contamination. And for each one of those factors the engineers or the project team can define how important that factor is in making a decision here. And every time you change the importance of a factor you can see then how the ranking of these sites compared to each other changes. So it's a dynamic model in terms of the way you can actually use information.

And then this next slide shows the executive summary. What this slide has done is pulls together all the information from all of these issue areas that are listed down the left-hand side, environmental, economics, including a section on costs. And pulls together and ranks basically the substation sites -- again, this is a substation example -- in terms of which one is best.

You can see here in the center it has another layer of priority rankings. You can set here at the big picture environmental versus community versus cost. If you want to play with, well, let's say, what happens if we make environmental less important than cost, most important, you can then see what the changes in the way that the different sites are ranked.

So that's a little summary of what SCE's done already. What we're planning on doing here, assuming this project is approved for us to proceed, is taking the SCE model and expanding it so it can be used on a statewide basis.

The process, and I'll explain a little

bit just briefly about where this process is going to go, it's expected it would be hosted by a regulatory agency. Obviously I think either the PUC or the Energy Commission would make the most sense.

And the thought is that it even would be hosted on the internet in a publicly available forum. So, to some extent, and this is something we'll decide as we work through it, the public would even have access to this to see sort of how it works and get an education on how these processes are done.

The way that we will approach the project as we get started to take the existing tool from SCE is to develop two sets of committees. And this is something we would do over the next six months.

The first is a high-level policy advisory committee that would really be giving guidance and research direction. It would be made up with maybe a couple representatives from the utilities, key state and federal agencies, and also community groups. We want to make sure that, you know, groups who have an interest in these projects are also represented.

In addition to that group which would meet, you know, only probably a couple times a year, we would have a series of technical advisory committees. And these are the people who are really going to help us get this model populated in an effective way on a statewide basis.

We would have, you know, a group of representatives from biology, including probably, you know, Cal Fish and Game, and Fish and Wildlife Service and experts that know where the data is available, how to best use available data, and make it useful in an electronic format that will allow these decisions to be made.

PRESIDING MEMBER GEESMAN: Let me jump in, Susan, and --

MS. LEE: Sure.

PRESIDING MEMBER GEESMAN: -- extend an invitation to my friend, Yvonne Hunter, to comb through your members as to who would be good representatives on either the policy advisory committee or the technical advisory committee. Because I think there's a real opportunity to better mesh with the interests of local governments in both of those committees.

MS. LEE: Thank you. Absolutely.

That's something. And we have a slide at the very end with some contact information, because this is definitely a group from which we would love to get recommendations on these panels.

The kinds of steps that the advisory committees will be doing is first basically be an education so the committee members really understand what the tool does at this point. And then talk through what we would want to change that the model does now. What we would change to make it more functional either on a statewide basis or on a corridor planning basis, based on what we know about available data.

We need to have a lot of discussion about weighting. This is always, this is the subjective part of a model. And this is the part that is subjective and controversial. And giving the model enough options in terms of setting weights that you can see, you know, what happens if you weight visual more important than biology. That's the wonderful thing about a tool like this, is that you can make these little changes and then see really what the different results -- what different results you get out of it.

There are a couple big benefits we see,

and I think these are probably obvious to most of you in the room. A huge benefit in the process of transmission planning. Just being able to compare a range of alternatives in the exact same format using a very comparable set of data.

The second point here I think is one of the biggest benefits here, and I'll talk about that just a little more, is the evaluation of alternatives, the understanding of tradeoffs, the comparison, and folks have talked about this earlier today, the importance of educating people about the engineering issues, the infrastructure requirements that we all have, and letting them see the pros and cons of requirements in terms of engineering and cost versus environmental issues.

One of the things we also think will help a lot here is when a project goes to a decisionmaker and they're required to make a decision on it, this model gives you a really visual way to demonstrate for a decisionmaker how the environmental document has gotten to the place it got by illustrating the process that was used and documenting really all the factors that went into that consideration.

And then ultimately the hope is that

this would allow processes to move on quickly. If we can accumulate all the data in one place, that it can really help the process move more efficiently.

Communication with stakeholders is a huge issue, as you all know. It's not that hard in this environment for a very active stakeholder group to slow down a transmission project or even to kill it. And to the extent that this tool can be used as an educational tool, both, as I said, to make people understand the importance of infrastructure being located somewhere and being located effectively. But also explaining the balancing process that has to go on in the selection of alternatives and balancing priorities.

We're hoping that by making that process much more transparent we could get stakeholder buy-in earlier and more efficiently.

We know that a model is not going to make opposition go away. Projects are still going to have opposition. But, again, we're hoping that the objectivity and transparency that you would get from a model like this might reduce that opposition, or at least allow everyone to understand from step one really how the process works, and allow us, as people doing the analysis, to incorporate what the opposition concerns are.

The schedule that we have for this project, it is something that we wish we would have available right now. We're just getting ready to start on the Devers-Palo Verde EIR/EIS. But it's going to be a couple years.

It's a 30-month schedule. The first step actually isn't shown on here. The Commission here needs to approve the contract, itself. And that's going to happen in June this year, or it's on the agenda in June 2005.

The first thing we'll do is establish these advisory committees. And we'll be doing that right away after the contract gets started. And we'll work very quickly the first few months because the real goal that we have is to get a real test of this model done this fall. And that's assuming we get all the data we need and at least take kind of a first shot at some of these waiting priorities and comparison factors.

We're looking at possibly using maybe the Imperial Valley study group's transmission project because they're moving on a very fast track and will likely have a proposed project and a range of alternatives that might be really perfect timing for us to use in the model if we get going this fall.

And then again the ultimate purpose of this project is to transfer the whole project to whatever agency is determined would host it, and that agency would maintain the data up to date all the time. And that's a huge challenge, in itself, because, you know, general plans are changing all the time and the state is growing. But that's the goal.

And this is the part where we would love to get comments. As I said, the first step is going to be to populate these advisory committees. And Kelly Birkinshaw and Linda Spiegel in the PIER program here and my contact information is on here for any of you who have suggestions of people you think would be good for these advisory committee, either at the policy level or at the technical level. We would love to have you either call or email us with names or even if not names, of groups of people that you think could be represented. We would really appreciate that.

That's it for me.

MR. BARTRIDGE: Very good, thank you, Susan.

Next up we're going to have a panel discussion. And if I could ask the people on the panel to take seats here. Duane with BLM, Richard Rayburn from State Parks, are you here? Okay. Yvonne Hunter from the League of California Cities. Don Haines with SDG&E. Chifong Thomas and Jorge Chacon from Southern California Edison.

Actually these next two slides refer back to the background paper that we put out. And will frame our panel discussion.

Staff feels it's important to answer four fundamental corridor questions in the IEPR cycle. They're here for you to look at in the background paper. The answers to these questions will help us make an informative corridor recommendations to the Commission for inclusion in the strategic plan.

So those four questions, what are the corridor needs of transmission system owners; given the corridor needs identified, what are the appropriate priorities assigned to those corridors; what are the major physical and institutional issues and government actions necessary to address those issues; and which local agencies are vital participants in identifying environmental and land use associated with the identified corridors.

Buck Jones, I'm sorry, Buck Jones with PG&E will be representing on the panel.

So these are our four questions. And, next slide, please. And the proposed 2007 corridor identification process would be that we develop a list of corridor needs from transmission owners, agencies and stakeholders as part of the IEPR process.

Stakeholders would then identify the issues associated with them, as well as any actions we can use to address those issues. And staff would summarize that input and vet in workshops during the IEPR process.

So the panel questions here, do the proposed corridor identification process described in the background paper, and laid out here, meet the needs of stakeholders, state and local agency and public concerns for a state-led transmission planning process. If not, what would you propose.

And secondly, how should the collaborative approach recommended in the 2004

Energy Report be structured, if there's another way.

So, we're looking for your input. And with that I'll just go ahead and, Duane, if you want to start us off. Have some comments?

MR. MARTI: I would agree on the first one. I think what I was trying to say is that the federal agencies can't plan in a vacuum. We do need all the other stakeholders to help us.

And we have identified corridors down in the California desert. We're trying to do it elsewhere in the state. But we definitely need to make sure our corridors are going to meet those of the utility companies and everyone else.

So I think we do need a state-led transmission planning.

MR. BARTRIDGE: Yvonne Hunter from the League of California Cities.

MS. HUNTER: I'm going to have to take a slightly different approach than just answering that question. And my comments are colored and vastly different than what they would be if SB-1059 had not been introduced. And I was debating whether even to mention it, but Commissioner Geesman commented on it.

I'm Yvonne Hunter; I'm a lobbyist with the League of California Cities. And except where in the future they disagree with me, most likely my colleagues from the California State Association of Counties and the Regional Council of Rural Counties probably agree with the general thrust of what I'm about to say.

One other comment. I know Southern California Edison is very able to speak for themselves, but I'm sorry, with all due respect, Commissioner Geesman, I take strong exception on behalf of local government and on Edison on your characterization of how they've handled SB-1059.

I think everything that George said from Edison's planning process is absolutely on point. And frankly, it describes what I've heard the Edison lobbyists describe as how the process works.

We surveyed some of our cities to get some information on how they work at the local level with the utilities, and it's very consistent with what is said. The problem is the heavy handed nature and the drafting, poorly and clumsily drafted provisions of SB-1059 appear to, at least local government, as a sledge hammer, as opposed to a collaborative, let's be reasonable and work this out process.

The computer model that Susan described is absolutely fantastic. And I'm not sure exactly who to contact, but please feel free to call me and we can help get technical people at the local level, policy people, because those are the kinds of issues that need to be evaluated for local governments to be comfortable on the thought process that's gone behind designating a corridor.

The stakeholders, all of them need to be involved; property owners, as well. You can't simply impose or demand on local governments to put everything on hold or change their plans, their designated land use plans, for a maybe corridor that may or may not be viable. It's simply unrealistic.

And that, I think, is the difficulty that the local governments have with how 1059 is written. There needs to be much more upfront work along the lines of what PG&E and SCE discussed, what is evaluated in the PIER program. We're happy to be at the table to participate in those discussions, because all local governments know about the importance of electricity and transmission line.

So, the process that's in the staff report really doesn't give us enough detail on what is contemplated and, unfortunately, with the overlay of SB-1059 we're not really sure what's being proposed.

So I wish I could be more positive. I can say that I know on behalf of CSAC and the League we offer whatever assistance you need to get the word out to local governments. If any of the utilities find that they can't get their local government folks to participate with them, please call us because each of your utilities has a League and CSAC liaison. We all work very well together and we're happy to help.

Thank you.

PRESIDING MEMBER GEESMAN: I appreciate your comments. We continue to welcome your input into the drafting process.

MS. HUNTER: Good.

MR. BARTRIDGE: Thanks, Yvonne. Richard Rayburn, California State Parks.

MR. RAYBURN: Thank you. Before I address number one, which will be very brief, I'd just like to mention that the California State

Parks system has about 278 units, parks, in California and all ten bioregions. So an effort like this is of great interest to us, in that it's going to have -- enables us to work both at a more general scale with our field people in identifying what is a good method of approaching corridor identification questions, as opposed to decentralized effort where we have a lot of field people working with a lot of energy planning issues, and being handled in a different manner.

The one real challenge to us is to, how to get the best information, engage our local field staff in collaborative efforts to require a number of meetings. And they just can't participate on that type of basis from throughout the field.

So it becomes a real challenge for me -- I should mention I'm the Chief of Natural Resources for State Parks -- as to how to put forward the best information in relationship to corridor identification process and the minimizing the impacts to the State Parks system, both in terms of overall methodology, bring forward some of the critical concerns that we may have.

Regarding question one, I've looked

through these items. I've given it a thought from a planning standpoint. It makes sense to me.

I was a little confused, and maybe somebody could address this, Jim or others, that's to number two. Discuss what are the appropriate priorities assigned to the identified corridors. Can you give me an example of that? Priorities for what, exactly?

MR. BARTRIDGE: Well, we would anticipate a number of corridors being looked at. so, at that point we'd have to determine what's needed first, what actually would go in, a recommendation that would go into the strategic plan for the Commissioners to consider.

If we had ten, and we have staff to look at three for processing-wise, we need to know how we'd establish the priorities for, you know, the top three.

MR. RAYBURN: Okay.

MR. BARTRIDGE: And that would be sort of a collaborative approach effort where folks could say, well, gee, we know a line is needed here this year. Let's look at this year and get started on that immediately.

MR. RAYBURN: Then we're just addressing

question one right now, is that right?

MR. BARTRIDGE: And two. Go ahead.

MR. RAYBURN: Two? Well, on two, how should a collaborative approach be recommended the report be structured. I think it's excellent that we'd be getting together especially groups that have a common interest like in the environment, which can be land use, as well as the regulatory side.

I know the Biodiversity Council, Jim has addressed the Biodiversity Council executive staff on how this would best be worked out.

I'm not sure that structure of the Biodiversity Council, which I've been a part of for a number of years, is the way to approach this in the long run. Although I think the results of what happened should be taken to that group as an example of what can be done. We get together to work out problems.

But I think there's, you know, there's probably only five or six of the agencies in the Biodiversity Council that you really want to spend some time with. And maybe those agencies, and possibly even the representatives from Cal-EPA and the Resources Agency being a part of that would be a more focused way.

I think it's a good idea to keep the Biodiversity Council in mind, but don't use that as the day-to-day avenue towards working with the state agencies interested in the land use and regulatory impacts.

I think at some point there -- I've been in a number of meetings where you kind of lumped the natural resource regulatory agencies with the land management agencies, and surprisingly not as much cross-over as you'd expect. So to get productive, I think my primary interest in the land use side of the question, you're going to want to get down, I think, to the meeting with the Bureau of Land Management, Fish and Wildlife Service, State Parks. While we only have 1.5 percent of California, being in all the bioregions, a lot of these corridors do conflict with our mission and need to be addressed.

I would add to that the National Park Service and Fish and Game as important land management agencies.

And again, I need to find a way to engage our district staff at the right times, but we will have an overall presence out of headquarters in the process for continuity purposes.

And we're only three or four months away from identifying, through natural resource strategic planning within our department, identifying those really key areas of the State Parks systems that represent the ten bioregions best, and are outstanding on their own. And that will help us in identifying how important -- how much time do we need to spend on one corridor versus another.

I think that's all I'm going to say about the questions. Thank you.

MR. BARTRIDGE: Thank you.

COMMISSIONER BOYD: Thank you, Rick, good to see you again.

MR. RAYBURN: Thanks, Jim.

COMMISSIONER BOYD: And I would say, based on my term of office at the Resources Agency where Rick and I worked together on issues, I can identify with and appreciate and concur with your recommendations. Appreciate the fact that you're part of the process and that you made the comments that you made and made the recommendations you made.

MR. RAYBURN: Thank you.

MR. BARTRIDGE: Don Haines.

MR. HAINES: My mind is really running in about five million directions right now. I don't know exactly where to start, but I don't know the gentleman next to me, but if he's with the State Parks I just want to commend the State Parks for working with SDG&E on the general plan that you developed for Anza-Borrego. And I think did include a recognition of the transmission line that goes through the state park.

Speaking of the State Park, I think of the State Park as like any other agency, it has a mission. And this is a generalization and I've been wanting to make it in public for a long time, so I'll make it.

And that is that transmission lines offer a wonderful opportunity for a society to deal with its biggest issues. The State Park has a particular mission which is in direct conflict with the transmission line. And that transmission line is in direct conflict -- its mission is in direct conflict with the local city down the road, et cetera.

And so we're faced with conflicting

missions and they're all legitimate. And so these are important societal issues that need to be addressed. And I commend the CEC for wanting to address them.

So in response to the first question, I think that most planners would recognize that the process that's being offered up by the CEC is a very typical, rather conservative process to identify the general need and work down from the general to the particular.

But if you've ever developed any type of a plan at all, you know that the top part is easy and the bottom part is really difficult. And when you get down into the local community, and you know, going from block to block, let alone from county to county, you run into all these conflicting interests. And then, you know, somebody has to make the decision. And it's not going to be popular with some groups. I mean those are all obvious things that any planner would notice.

So, you know, I commend the CEC for the general approach that I would take on myself. But, then I warn them that they will hear at the bottom of the process, and I think the fourth --

can't remember the fourth one -- which local agencies are vital participants.

Or there was one where we run into problems. And I don't remember the woman -- Yvonne?

MS. HUNTER: Yvonne Hunter.

MR. HAINES: Yvonne. I think that, you know, she represents all of the comments that we faced when I talked about to different jurisdictions. And these are legitimate concerns, as well.

So as you work down into the local agencies you're going to have problems resolving conflicts.

So it's a good process; it's a tried and true traditional process. But it takes a long time. And it may or may not work. Sorry for that.

One last thing. About corridor planning from a kind of technical standpoint, if you were to ask my company where would be the perfect corridor in 25 years, because remember there will be no land left in 25 years, we wouldn't be able to tell you that.

We might be able to say -- I mean, who

knows. There might be some floating generation station out in the Pacific that we would need to bring power into. We have no idea about that sort of thing. We have predictions that maybe go out ten years, you know, for population growth. We do the best that we can.

But for long term, I mean we've got to do -- we need the planning to occur right now, and we can't really predict growth. And growth is what drives your transmission needs. So that's even a tough process.

Now, I'm trying to get away from the negative and into the positive because I do believe in this, and I'm here because I do believe in it, and I think that we need to keep talking.

But you're asking the right questions, and I'm afraid that I can't give you many answers. I'll wait for something, and that's all I have to say at the moment.

COMMISSIONER BOYD: You should try sitting up here. We're only dealing with one of the three legs of the energy stool, electricity and transmission line therein. If you want to shift over to the natural gas leg of the stool, there are pipelines --

MR. HAINES: I've got lots to say about that, too.

(Laughter.)

COMMISSIONER BOYD: And you want to go to the third leg, transportation fuel, there are pipelines and storage tank farms, et cetera, et cetera.

And as you say, there's no middle of nowhere in California anymore. And your dire prediction about there'll be no land in 25 years just further complicates the issue. So if you'd like to be prematurely gray, why take on all three.

MR. HAINES: That's happening fast enough as it is. The grayness, that is.

MR. BARTRIDGE: Next Buck Jones with PG&E.

MR. JONES: Certainly thank you for having us here today. And I could only reiterate in spades what we just heard.

I'd like to relate one or two short examples of my past 30 years of being in this business for PG&E. We set about in the early '80s with Santa Clara County to develop exactly what we're talking about here. An organized county-wide plan that would dedicate and reserve substation sites and transmission link corridors, because as we're all now well aware, Santa Clara County had in their vision an enormous future. And, of course, most of that has, in fact, come to play.

We got very far along in the process while over a year spending lots of time in workshops with individual property owners that would, in their mind, like to develop their property for high tech uses, industrial concrete tilt-up, whatever you want to call it, and residential, of course, hospitals, everything that was involved in the plan.

The bottomline that came out of that was as we're all in this business quite aware, someone's ox gets gored. Now, when you start to put a reserve substation on a site, a reserved 140-foot wide, 200-foot wide, whatever, corridor on the site, you are de facto changing the opportunities to use that property.

It was mentioned here earlier about how is this going to be compensated. At that point you don't have an approved plan. You don't have a certified EIR. You don't have a certified document that says this particular land will be used for this purpose. It's a planning tool.

I challenge you to find someone willing to volunteer their property for that purpose. It just won't happen. You'll get yourself mired into a never-ending political football about well, put it on the other side of the street.

In 30 years of doing this business I've never had anyone ever come to me and say, sir, I volunteer my property for your purposes. It just doesn't happen. That's sort of my first comment.

Notwithstanding, we have raised the opportunity to try and move this forward. I think the thing that concerns us the most is that, as many have said, this is a five- to seven-year process as we see it. Frankly, I don't see that as a bad thing.

Our planning horizon for growth is directly related to what we hear from the communities. We consult with them on an ongoing basis. We meet with them regularly as they propose their development plans. And beyond that, PG&E, in its service territory, meets with those key developers and property ownership interests, insurance companies, doesn't take much to go out and look at the property ownership map. Looks like Farmer Brown's property.

You look at who owns it, it's Metropolitan Life Insurance. Well, why do they own it. They plan on developing. So it may well look like it's two miles away from the freeway, but they already have within their board room, within their planning department, key information that will tell you what their proposals are.

So if we start to look at this long-term process we have to get those people into the room, also. That's extremely hard to do because it's a proprietary piece of information that they don't want out in the public, to tell their competitors what they're planning to do and when that's going to happen.

So to garner all this information and then come up with a plan, you got to get all these people around the table. I have been, and I will admit, unsuccessful in 30 years figuring out how to do that. It's just almost impossible to get these people to agree, first that there's a need.

The education portion of this is long overdue. We got to do that. We got to explain to people how electricity works; how it gets to their front door; and get them engaged in the process at the local level to understand it will come into your community.

How many of us have seen communities say, well, I got my substation, I don't need another one. Even though their growth, which they, in fact, are responsible for determining, it's not the utility that determines what gets built there or how they annex or any of the other issues. The community has to take interest in it and say we want to participate and we will participate.

I think they're willing to give you information, but they're not willing to go the step and dedicate vacant property for this purpose. I think it's going to be extremely difficult to get them to do that.

Five- to seven-year planning horizon is what we work with. We sort of look at our load growth and we look at the general plans. And we see that maybe out five to six to seven years we think that capacity curve and the load curve are going to intersect and we start doing our planning.

I don't think it's a bad process, the

one we have today. And I caution you that prior to general order 131D, enacted in 1995, we didn't have the requirement to go through the CPCN process at the Commission. It was done at the local level. And I'm sure many of us here at the table could add that there were numerous horror stories trying to get certification, conditional use permits or whatever you want to call them locally, to get these facilities sited.

We welcomed 131D because it took the responsibility for 50 kV and above to the Commission. The Commission had to come in and make those hard decisions.

The one thing we'd like to ask is that if we move forward on this process, let's look at the five- to seven-year window and ask ourselves are we making it better, or are we going to make it worse by trying to engage a very large information-gathering effort prior to getting a project certified. I caution you I'm afraid that's what's going to happen.

Thank you.

PRESIDING MEMBER GEESMAN: So what do you think the state should do?

MR. JONES: I think the present 131D

rule works just fine, if it's kept within the permit streamlining act requirements. I think we need to spend more time transferring the utilities' basic data that they put in the PEA into the Commission's review process at the environmental level. And do that together. Don't do that lock-step, we do it first, hand it off, they do it next.

If we can do that together as a utility and the Commission responsible for environmental review, we can save a year right there. That's a gimme, that's a freebie.

Next step, once the utility has decided there are certain alternatives that, in fact, meet environmental and engineering and cost considerations, let's not go invent a whole lot more. The more we invent, the more people we engage. And I have yet to see an example where there's additional alternatives proven to be any better than what was submitted by the utility.

I'm sorry, it's just my opinion. But that's my experience in the PG&E service territory. So leave it the way it was filed unless there's obviously something wrong, and go ahead and review the environmental process. We know we can just about build anything anywhere; it's not that difficult to come to conclusion on the costs. The environmental issues, do we have anything we can't mitigate? No.

There are community value issues that are extremely important. That's one of the things the Commission and the CPUC takes great pains in reviewing. And I think that's one area where we need to come to agreement on, how can we rank the community value issues, when, in fact, the community being served is the one that doesn't want the facility passing through their city limits. That's something we can work with the community on. And I think PG&E feels that it works pretty well at the local level.

Again, somebody's not going to be happy with it, but remember this process isn't meant to make everybody happy. It's meant to make the best environmental decision for the long-term benefits of the communities that we're serving. And that's going to hurt somebody; somebody's going to have to give something up.

So just stick with the current program. Stick with the current 131D order and enforce that 13-month timeframe that we're supposed to turn these things around. Work with the utility at the same time so the data doesn't have to be duplicated. I think we can cut a year out of the process right then and there.

That's one offer, one opportunity.

PRESIDING MEMBER GEESMAN: What's your experience with that 13-month timeframe?

MR. JONES: Is Ms. Lee here? Certainly, you know, the smaller projects, the ones that are out in the Geysers up in Lake County where you've got a short connection to make, you can do those. We can get those approved seven, eight, nine months.

The big ones, the ones we're talking about that we're concerned about here, double that timeframe, maybe more; 24 months, 26 months. Double, anyway.

PRESIDING MEMBER GEESMAN: Yvonne.

MR. JONES: And I'm not saying that the review that's done is overboard or unnecessary. It's just that if you start to expand it once we file our alternatives, and we put two or three or four into the mix, and you start getting four or five or six added to it because of public input that says, well, what did you look at over there and what did you look at over there. Then the thing balloons. Then it really does go 24 months, 20, 24 months, something like that. And then we've lost another year, so.

It's very difficult for the utility to plan this five- or seven-year horizon if that starts to happen. We start doing things like buying General Electric combustion turbines to stick in places in and along the way to keep the voltage support up. Poor planning, but those are the kind of options we end up with. And that's not good for anybody.

PRESIDING MEMBER GEESMAN: Yvonne.

MS. HUNTER: Thank you very much. I'd just like to make one observation. I think in all of these discussions we need to make a distinction between what, and I may be wrong, sounds like route planning, permitting, processing and corridor planning, which in a, what is it, 1989 CEC document, described it as three to five miles wide.

There is nothing in SB-1059, and that's one of the questions that gets peoples attention at the local level and at the property-owner level.

If the Commission or the utility or the ISO or anyone says we know for sure, we need to go from here to here. Now we're going to work with the local governments and the property owners to figure out what is the best route, we already know the PUC has the authority to give the utility eminent domain to get the property and go. And that's a process that the local governments and I think property owners are familiar with and are comfortable with.

It's the uncertainty of this three- to five-mile swath. And when I talked about the difficulties in drafting 1059, I mean in the legislative process, the difficulty is always does the language in the bill reflect what those that are conceiving it have in their head for intent. And that's one of the arts of drafting language.

But, I mean, you know, you have somebody with a Magic Marker going like this. And you end up getting everybody's attention in a not very positive way at the local level if that's what they think is going to happen.

So we need to distinguish between corridor planning and routes.

MR. JONES: That's an excellent point.

I'm assuming, maybe that's a bad assumption, that what we're talking about here is large-scale transmission routing between generation resources and, you know, existing substation delivery at the regional level.

If you're talking about using this as a process at the local level for what we in our parlance call an area substation, a three-bank substation to serve a community, we got to come to agreement on that. That should not be included as a part of this.

We see corridor planning on the large state scale basis. I use a number, and correct me, in your service territory something like 50 miles or 100 miles, or something of that. Not the 10-, 12-mile job that you have to do off the existing system into an area that is now burgeoning development-wise.

We got to separate those two. They can't be the same, they can't be the same process.

PRESIDING MEMBER GEESMAN: I agree with that. Somebody asked our staff in one of the meetings in the Legislature, well, how many of these do you envision having. The answer was four or five.

So I think a lot of us are talking past each other. But I certainly agree with the point both you and Yvonne made, that we do need to bring greater clarity to some of these planning concepts.

MR. BARTRIDGE: Jorge Chacon, would you like to go ahead now.

MR. CHACON: I think for the most part for the items listed, I think they're good. I think Edison shares some of the same concerns that have been discussed, and I think our comments to the Senate Bill goes to that extent, to identify that.

I think it's also true that for load growth, you know, we do have our ten-year load growth horizon for which we can plan facilities. And although it's not a perfect process because the load growth always changes, for the most part the changes aren't substantially different that would drive a different facility or a different corridor.

It's rather the unknowns, you know, the renewables, where the generation's going to come. We're no long vertical integrated utilities. So, you know, not knowing where the resource is going to be at, sort of does provide an unknown feature that makes it a little difficult to, with more precision, say okay I need a line from point A to point B.

We know from the renewable resource report that was filed with the Legislature where, for the most part, the renewable resources are at. But I think in other proceedings San Diego's comments have been that while that report is out there, their response to the RPS was not tracking with what was out there. So it is somewhat problematic if the developers, themselves, are not engaged in the process early on so that you can articulate with more clarity what the corridor ought to look like. I think that goes to question number one.

As far as question number two, how should the collaborative approach recommend the report to be structured, I don't know that I have a good comment for that. I think there needs to be a lot of involvement and a lot of participation to try and satisfy everybody's requirements. And it's a long list of everybody.

So, you know, I just don't know how. I don't have a vision how the report's going to look like.

PRESIDING MEMBER GEESMAN: Let me ask you. If land is finite and the state's interests seem to be dominated by a desire to develop a particular level of renewable resources over some period of time, if we know where those resources are in general, if our ability to calibrate time or our crystal ball is at least 10 or 20 percent worse than yours, and if we can only think in rough increments four or five major transmission corridors in the state and some planning horizon, and if tough decisions need to be made, the state is convinced that the best way to do that is have political appointees and some commission somewhere appointed by the Governor, being the one stuck with making those tough decisions, is there some better way to do this?

I mean it would seem to me you'd want state government engaged sufficiently in advance to take some of the heat out of these decisions that will invariably be tough and controversial when you get to a final permit.

But isn't there a way to shift some of the larger debate into a planning forum?

MR. CHACON: Well, I think for the most

part what you end up getting is identification of a corridor that would suffice. It may not be the optimum location, but it would, you know, we can make it work.

PRESIDING MEMBER GEESMAN: So you come back in a couple of years --

MR. CHACON: Right.

PRESIDING MEMBER GEESMAN: -- and improve upon it.

MR. CHACON: Well, I think the issue is the corridor, itself, we can make work. It's, you know, beyond, say take Tehachapi for example, where we know in our CPCN where substation one ought to be located. It is beyond that substation to get out to the renewable resource where it's rather nebulous. And there's a lot of unknowns.

The corridor, itself, I mean now we've filed the application we're finding that we have to, if you will, reroute sections of it because new housing developments have occurred that weren't on the books when we first started.

So we're working with the local jurisdictions to accommodate the needs there. And we do what's necessary to try and work with everybody involved and come up with a better plan or better alternative that suffices everybody's desires.

So that, in and of itself, requires us to go back and do a little bit more work, and it delays the process and, you know, that's why you get to this 24-month extended window as far as the permitting process is concerned.

But for the most part, assuming that the development wasn't there and we were to construct the corridor and the line in its place, even though it may not be the optimum in the end because the renewable resource was a little bit further away, I don't believe that that major piece of line would be that far off in terms of making it work.

It is the details, when you get down into the weeds and try to figure out how it is that you're going to integrate all this renewable into this one location that is sort of rather nebulous.

PRESIDING MEMBER GEESMAN: Yeah, Yvonne.

MS. HUNTER: Notwithstanding all of the venting that I did previously and concern about rolling over local government, I want to make it clear we understand and appreciate and support the need for good long-range planning. And I mean the health and welfare of the state depends on a stable and reliable electricity supply.

And if, indeed, what is being contemplated are four or five corridors, or the need in the future, I think a robust, upfront planning and evaluation process similar to what we've heard here, with the PIER process, engagement of all local governments and property owners, so that the farm that's owned by the insurance company, they have a right to know what's going on because they have plans, the local -- we have housing, building needs, affordable housing needs, all of that.

But, if indeed, after all the best evaluation and input the state can put together, and if in -- let's just assume it's 100 percent excellent upfront planning with stakeholder involvement. And you're basing your corridor decision on the best available information that you have.

And the corridor -- I mean 1000 feet, whatever, a mile, three miles, if indeed the state truly believes that that is where they need to have some eventually transmission lines go, then the state should consider some sort of easement or process for consideration, financial consideration for the property owner that you want to hold it for future use.

And that if the local government decides for whatever reason, or the property owner, wants to proceed with a development that would be inconsistent with that future use, public debate, public discussion, and perhaps maybe that project or that individual development is three years after this corridor was designated, the Commission might want to go back and reassess. Do we really think we still need it. Or is it going to be over in this location instead.

That kind of deliberative give-and-take process where there is some financial consideration given to the property owner for the uncertainty that they would have on what they can do with their property.

I'm not an attorney, and by no means do I -- am I anywhere close to an expert on takings issues, but I have been told by a number of folks that while this may or may not actually be a taking, if we take the 1059 model and -- SB-1059 model, local governments have to amend their general plan, and I won't even get into those problems.

Maybe this won't be a taking. But we will get stuck defending it. And that's not going to be a good use of resources.

So, I think there's certainly room for some creative thought that may get the state 80, 85, 90 percent of where you want to go without rolling over everybody. And we're happy to engage in those discussions.

MR. BARTRIDGE: Don, go ahead.

MR. HAINES: I'd like to support both those prior testimonies. There's a couple of points that they made that I think are really critical.

One, I think that a collaborative approach is the only approach. I don't think you should even be considering anything else.

But a collaborative approach has to end in some result. And whatever that result is somebody is going to have to make the tough decisions that you're suggesting.

And I think that role is probably best with the state. They probably have the easiest time of making that decision.

And I think that as a utility I agree that we can probably work with four or five corridors. You know, it's not ideal. There's going to be some expense in them being too far from where they really should be, but, you know, that might ultimately be the solution for 20 years from now. And the only solution. And so it does need to be done now.

The only cautionary part of this, I think, is that however, whatever the result is, the body that makes these tough decisions has to continue to make tough decisions. And I think that, I wanted to say something, I think there is a lesson in 131D. 131D really really was welcomed by the utilities, and I think that it works very well.

However, I've seen in the last five years the process has slowed down, and I think that comes from the desire to be inclusive and recognize everybody, but the collaborative approach, I thought, took place before 131D, and now the tough decisions need to be made.

And so when something -- and this is where the fights will all occur. When you make that decision, if you're going to be absolutely hearing every single person's voice and make your decision based on two years of hearings and two years of planning, then 131D is no longer working as it was envisioned.

So, I think that that's a cautionary tale about whatever comes of this type of corridor planning. You have to have a group that can really make tough decisions and know that their role is no longer to be listening to everyone. The process took care of that.

MR. BARTRIDGE: Are there any other comments? Anyone in the crowd would like to make a comment, please come up to the podium. No. Anyone on the phone? No.

Okay, well, that wraps up the first part of our workshop today. I'd like to thank all of the panel participants for your input.

(Whereupon, at 11:58 a.m., the workshop was adjourned, to reconvene at 1:00 p.m., this same day.)

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AFTERNOON SESSION

1:08 p.m.

MS. GRAU: Okay, my name is Judy Grau; I'm with CEC Staff. And I'll be discussing some 2005 IEPR strategic transmission planning activities we're working on.

Second slide is just an overview of what I'm going to talk about. I'll skip that.

Okay. In August 2003 staff published a report entitled, upgrading California's electric transmission system, issues and actions. And the IEPR Committee then held a workshop on that staff report.

The staff report, along with input received at and after the Committee workshop, as well as all the other staff products and input from utilities, government agencies and stakeholders during the IEPR process, were considered by the Committee in the formulation of the Commission's first Integrated Energy Policy Report.

Both the staff report and the 2003 Energy Report agreed that there was a need for improvement in the following areas: First, there's a need to improve the analytical methodologies for evaluating the costs and benefits of transmission projects.

There's also a need to evaluate the impact and value of the low probability, but high impact event, and make that information available to decisionmakers.

And third, there's a need to compare the costs and benefits of transmission projects against nontransmission alternatives in the planning process, rather than waiting until the permitting process.

Similarly, in July 2004 the staff published a sequel transmission report entitled, upgrading California's electric transmission system, issues and actions for 2004 and beyond.

Again, the IEPR Committee held a workshop on the staff report, and then considered the staff report, as well as input from utilities, government agencies and interested stakeholders to create the 2004 Energy Report update.

Again, the staff report and the 2004 update were in agreement on their major recommendations. The first major recommendation is that the state needs to initiate a comprehensive statewide transmission planning process that does the following:

First, assesses the statewide need for reliability and economic transmission projects, as well as projects that support the renewable portfolio standard implementation.

Second, that approves beneficial transmission investments that can move into permitting. Third, that examines corridor needs. And, fourth, examines alternatives early in the planning phase.

Next slide. The other recommendation, major recommendation, arriving from both the 2004 staff report and the 2004 Energy Report update is that there's a need to improve the transmission cost/benefit assessment to accomplish the following:

Capture the long life of transmission assets.

Two, capture strategic benefits such as insurance against contingencies during abnormal system conditions; price stability and the mitigation of market power; the potential for increased reserve resource sharing; environmental benefits; and achievement of state policy objectives such as development of renewable resources.

And third, use an appropriate discount rate that reflects the public good nature of transmission.

Just as the 2004 Energy Report proceeding was wrapping up, Senate Bill 1565 was enacted. It added section 25324 to the Public Resources Code requiring the Energy Commission to adopt a strategic plan for the state's electric transmission grid in consultation with the Public Utilities Commission, the California Independent System Operator, transmission owners, users and consumers.

The legislation requires the strategic plan to be included in the Energy Report to be adopted this November 1st.

And so this year the staff will be producing a transmission staff report that not only provides a portion of the record used to develop the 2005 Energy Report, but that also provides a foundation for the Commission to create a strategic transmission plan due at the same time.

And as Commissioner Geesman mentioned in the opening remarks we don't know for sure what that plan will be, but we are proposing a staff report that we believe will provide, again, the foundation for what the Committee and Commission eventually decide that plan should look like.

And so at this point staff envisions its staff report to cover the following topics: First, a chapter on the status of California's existing transmission system that would address items such as local reliability concerns, congestion concerns, and the ability to connect renewable resources.

Second, a chapter on the status of California's existing transmission planning and permitting process which I will discuss more in a moment on another slide.

Third, a chapter which assesses near and longer term transmission projects and paths, which I will also discuss more on another slide.

Four, a chapter on some of the major transmission issues facing renewables development. This chapter will draw from the results of IEPR workshops on February 3rd and May 10th on operational issues associated with renewables integration. The April 11th workshop on geothermal issues. The May 9th workshop on renewable resource potential in California and interstate renewable resources, and related Public Interest Energy Research work.

And fifth, a chapter on the identification of corridor needs for long-term transmission projects and paths which we discussed this morning.

And now a little more detail on the content of the proposed chapter on the status of California's existing transmission planning and permitting processes.

We plan to address items such as the following: an analysis of Southern California Edison's Devers-Palo Verde 2 and Tehachapi projects vis-a-vis the 2003 and 2004 Energy Report recommendations.

Southern California congestion issues. The quantification of reliability operational benefits from so-called economic transmission projects. And evaluation criteria for transmission and its alternatives.

And on our chapter on the assessment of near and longer term transmission projects and paths, there are four problem areas that staff will be focusing on as noted here, the San Diego-

Imperial Valley area; southern California in general; the Tehachapi area; and the San Francisco Bay Area/northern California.

The primary data sources we're using to evaluate these areas includes the resource adequacy filings that are made by all the load-serving entities; the monthly AB-970 filings that the IOUs make to the PUC; the joint energy agency watch list that is updated periodically; and relevant Cal-ISO/Western Electricity Coordinating Council and Federal Energy Regulatory Commission documents.

Next slide. The staff has retained three consultants to look at the issues noted on this slide. Those consultants are here today and will provide updates on their work.

First, we have Joe Eto of the Consortium for Electric Reliability Technology Solutions, CERTS, who will present the results of his review of the Cal-ISO's economic evaluation methodology for the Devers-Palo Verde 2 project; and his review of Southern California Edison's FERC and CPUC Antelope transmission project filings.

Then we have Peter Mackin of Navigant who will present his work in progress on southern

California congestion issues, and the quantification of operational benefits of economic projects.

And the third speaker will be Eric Toolson of Pinnacle Consulting who will report on his work in progress on the development of evaluation criteria for transmission and its alternatives.

Next slide. And so with respect to next steps we're expecting to publish our transmission staff report on July 14th. That report will include as many of the final results from our contractors as are available in time to meet our publishing deadline.

And we've tentatively scheduled a Committee workshop on the staff report for Thursday, July 28th. That workshop will also provide the opportunity for our consultants to present the final results of their work.

So if you notice on the agenda for today's workshop we called it corridors and strategic plan update number 1. So the one on July 28th will cover not only our staff report, but will also be considered update number 2 because we will have some new results that are not available today to discuss at that workshop.

And so with that I will turn it over to Joe Eto.

MR. ETO: Thank you, Judy. Good afternoon, Commissioners, staff, workshop participants. My name is Joe Eto; I'm a scientist at the Lawrence Berkeley National Laboratory. My work there primarily involves management of the program office for the Consortium for Electric Reliability Technology Solutions.

CERTS, as we refer to it affectionately, is an R&D consortium devoted to public interest electricity reliability R&D questions that have arisen as a result of the transition to competitive markets.

For the last several years we've been supporting the PIER energy systems integration program in a variety of R&D projects, among them transmission planning. And that's from the basis from which some of this work derives.

A year ago we were tasked to conduct a series of reports that were used in prior generations of the IEPR, and that will be the basis for my remarks today.

Specifically with respect today we've

been asked to speak to two, and I'll make two separate presentations. The first is to look at the evaluation methodology that was used by the California ISO in reviewing the Palo Verde-Devers line number 2 vis-a-vis some of the recommendations we had made last year regarding assessing the strategic benefits of transmission.

After that I'll make a very short set of remarks about a much smaller scale review which we were asked to compare filings made by Southern California Edison on the Antelope transmission projects with respect to the consistency and our observations about the filings that have been made both with the PUC as well as with the FERC.

Next slide. So, the background for this initial bit of work is that we have conducted three studies previously. And let me just summarize the outcome of those studies.

The first study, planning for (inaudible) transmission grid, future transmission grid, highlighted the fact that there are many historic projects that we've built for transmission in California that have had significant economic and reliability benefits for the state which were not originally considered in the original conception or justification for those projects.

The second project, California electricity generation and transmission interconnection needs under alternative scenarios, was a 20-year-ahead look at the California energy future, looking at very reasonable projections for efficiency, for renewables for instate generation, and concluded that there would be a need for additional transmission as an integral element of California's energy future.

Finally, we looked at specifically taking some of the findings from the very first report; made a number of suggestions reviewing specifically the California ISO team methodology for ways that that might be enhanced to begin to capture some of the strategic benefits that we'd identified earlier as part of a planning process going forward looking at future transmission projects.

And it is that final report that is the basis for the evaluation I'll be presenting this afternoon, which is to take this Palo Verde-Devers 2 filing, and then look at this updated team methodology application and again review it from the standpoint of those strategic benefits that we'd assessed and identified earlier.

Next slide, please. Let me refresh you on what we found in our report, which were that there were a number of strategic benefits or values associated with transmission that are not currently captured in a direct fashion in the existing planning transmission planning methodologies.

They are being addressed at different degrees and we encourage more work along this. Some of them are being addressed to varying degrees and I'll point that out in the context of this review of this specific application of the methodology.

The first has to do with price stability and decreased market power for existing generators. Essentially transmission gives you access to a larger market, decreasing the market power of the generators within the former more narrowly constrained market.

Increased potential for reserve sharing and firm capacity purchases. In particular, insurance against contingencies against abnormal system conditions. And this really is a reliability benefit of having access to resources that you would not otherwise have access to, through the availability of this transmission line.

I think there are also environmental benefits that need to be taken careful account of. They can go both ways, that's why the accounting is important.

And I think in addition, looking, stepping back from electricity alone there are some larger infrastructure questions that as a state are appropriate to address in these types of planning, with regard to the interaction between natural gas and our electricity infrastructures.

So, very quickly, we took the California ISO's board report prepared by the department of market analysis and looking at the PV-D-2. We held it up against the strategic benefits we had identified in our earlier evaluation. And we attempted to sort of go down the list and see to what extent some of those benefits that we'd identified are being captured currently by the existing evaluation method.

One of the specific recommendations that came out of our earlier report was a recommendation to use a social rate of discount, looking at benefits when considered from a societal perspective. And so we've actually made an effort to try to apply that in the setting of the numerical results that were presented in the CAISO report.

Very briefly, I think many of you folks know all this information already, Palo Verde-Devers 2 is to build a 200-mile, 500 kV transmission line, essentially a second line to bring power from Palo Verde to the Los Angeles area. The anticipated online date would be 2009. Capital costs about $600 million. Idea to be to import a large amount of gas-fired generation that's being built in the Palo Verde area.

The team methodology which CAISO has put together and used to evaluate Palo Verde-Devers 2 has a number of elements to it. I think the most basic element that everyone's familiar with is the issue of energy cost savings. The idea of the differential in price between production cost by serving load with generation from that remote location versus serving it from other sources.

Operational benefits are also considered. The primary one that I think is spoken to in the CAISO evaluation is the reliability benefit of having a second line from the Palo Verde area to bring power to the California market.

Also the issue of capacity benefit and the costs of capacity are compared between Arizona and California. Loss savings are addressed. Engineers will quibble with the adequacy of using DC power flows to do that.

And then finally there is an offline calculation of NOx reduction due to construction of the line.

In the CAISO evaluation I think they do a good job of trying to begin to identify some of the different perspectives from which you would begin to evaluate costs and benefits, starting with the introduction of a societal perspective that looks at the entirety of WECC without distinctions among consumers, producers and transmission owners.

There's a modified version of that societal test that's included there, which in the cases in where they look at the opportunities for -- and one of the unique things about the CAISO methodology is there's an attempt to begin to look at producer markups as a way of reflecting market behavior. It's the very beginning stages of development, but by excluding those essential rent transfers, we come to this modified societal calculation.

In addition, of course, there are like the traditional ratepayer perspectives. Notably there are two of them. One based entirely on the LMP approach; the other based on an LMP and contract path approach, which sort of respects existing contractual agreements for transmission.

Importantly for our analysis later on these are all evaluated using a single discount rate. And that's what it will comment about, the appropriateness in the context of the difference between looking at a ratepayer perspective or a ratemaking perspective versus a societal perspective.

Very briefly, these come directly from the report. They do a lot of scenario analysis, a lot of multiple scenarios; 66 cases in all. So a huge range of benefits or of impacts are estimated and valued at these different perspectives. An expected value is chosen for each one of them. They look at two single years.

Turning to the benefit/cost ratios they find that using this discount rate to levelize these -- a common discount rate to levelize all these benefits, that the benefit/cost ratios are all greater than one, indicating that the project would be cost effective under the analysis that they've conducted.

So that's what you can read from the report. What we've tried to do now is compare what has been done with the report with some of the recommendations we've made, we've done strategic value.

And in particular we lined up here the five areas of strategic benefits: price stability and addressing market power; potential for increased reserve sharing and capacity purchases; insurance against contingencies and abnormal system conditions; environmental benefits; as well as construction of additional infrastructure.

Then we line up both the original California ISO presentation and the team methodology as reflected in presentations that they had made approximately last April with this most recent report in which they've updated and expanded their methodology to some extent to prepare this analysis of Palo Verde-Devers 2.

And what we see is that, you know, there are efforts to begin to address this market. Power issue, as I've already indicated. There is an effort now to include looking more at this reserve sharing question. I think the basis, and we'll speak to this question of the insurance value, is addressed both in the original report, as well as in the more expanded update through the use of the scenario analysis.

We have additional ongoing work for PIER in which we're going to trying looking at this scenario more from an insurance premium perspective, which we think is another way of capturing some of the value of that type of scenario analysis.

There's an effort to look at nitrous oxide -- nitrogen oxide emission methods, as well, that was not present in the earlier study.

So there has been movement in the direction of trying to capture some of these strategic benefits that we had recommended earlier. We think that's very good progress.

In terms of recommendations going forward, we think that again the looking at the single-year snapshots as opposed to a time series of individual, of connected years, understates some of the interactions between the capacity value estimation and the transmission generation -- transmission and generation expansion question.

We think again using expected values when you calculate this large distribution from these scenarios is the tip of the iceberg in trying to capture this insurance value. Yes, it's good from a scenario perspective, to look at some of these extreme scenarios, but I think the next step is to begin to take advantage of that diversity of outcomes and start trying to think about how you would value them from an insurance perspective in terms of what it is you're trying to protect yourself against, and what is that worth to you.

We think that there are additional environmental benefits to be considered in these types of evaluations. And we think that, again, looking at the infrastructure investments, needs to be considered from a holistic perspective that also looks at some of the gas infrastructure issues, as well.

What I want to turn to next is a

specific area of recommendation that we had made which was that when you look at the societal perspective and you think about transmission as a public good, it is appropriate to begin looking at using a societal discount rate to look at the value from a societal perspective.

And so, again, our comment and observation in looking at what the ISO has done is they've used a common discount rate, the weighted average cost of capital, to value all of the four different cost/benefit perspectives that they present.

We would recommend -- or we would observe, while that is entirely appropriate from a ratemaking standpoint, when you're actually trying to do a societal cost/benefit analysis, it would be more appropriate to use a societal discount rate.

The ISO acknowledges this directly in their report and has a footnote indicating that had a lower discount rate been used to represent the societal perspective the benefits would essentially double from the calculation that they present.

So let me show you what, in effect, that might look like. This is taken largely from the report, itself. Excuse me, I'm back one slide, please. Okay, can we go back one slide? There's a table that you seem to be missing. There we go, thank you.

So these are all from the report. But this is what we've done here, is to take a social discount of 5 percent. And what you see, the effect is dramatically increase the energy benefits and increase the benefit/cost ratio, holding everything else fixed. And we think that is appropriate from the standpoint of looking at these kinds of costs from a societal perspective. And that's a direction that we would encourage in future applications of a societal cost/benefit perspective.

So, in summary, you know, our review indicates that, you know, as presented the benefit/cost ratios are all greater than one, and they're all -- all the perspectives considered, a number of the strategic values that we've identified are starting, and the beginnings of that are beginning to show up in this more revised. We think there are additional strategic benefits and values that should be captured going forward, and we've made some suggestions for how that might be accomplished.

One particular area to focus on is again the social discount rate when evaluating societal perspective.

That concludes this first presentation. What I think I'll do is I'll jump straight to the second presentation and then take questions at that point. So, Judy, can you switch me over? Thank you.

This second presentation is of a slightly different flavor, in that really it's a very modest effort here. Not again to look at economic methodologies, because we were not asked to -- the economic methodologies are not presented here. These are applications that Edison has made both to FERC, looking to FERC for cost recovery of guarantees in advance of some of the resources that would be developing that would normally justify those types of upgrades. And also applications to the CPUC for the CPCN, again in advance of the resources that historically would be further along when these applications would come in. So these are somewhat unprecedented in terms of the type of applications that they represent.

We've been asked to essentially line the two applications up, or two sets of applications up in the case of the PUC there's two applications, and just make some, you know, observe to what extent they're consistent or inconsistent with one another. And offer our observational comments about them. So this is going to be a very brief set of remarks on that topic.

Briefly, the proponent of the application, Southern California Edison, objective is to contribute to the state's renewable energy resource goal of interconnecting the approximately 4000 megawatts of renewable generation that's been identified in the Tehachapi area.

The first elements is a three-segment project. I'll show you some diagrams of what's being proposed specifically. Together those projects are intended to bring an initial 700 megawatts of power onto the system.

The timing is such that the first one's supposed to be in service by 2006 to bring about 200 megawatts online.

To summarize, as a result of PUC

decision 04-06-010 Edison was ordered to make filings both with FERC for cost recovery, as well as with the PUC for the CPCNs for these projects.

And so, again these are somewhat unusual in that they're being filed in advance of having interconnection agreements in place for these resources. And, in particular, these are trying to address, you know, what has appeared, you know, over and over again as one of the key financial bottlenecks of transmission expansion is the issue of cost recovery.

And specifically the FERC application and the PUC application to support it really are about trying to insure from Edison's standpoint that in advancing the state's renewable objectives by building this transmission in advance of these resources coming online, that they will not be injured financially should there be changes in plans essentially; that they will be able to get cost recovery for those investments that they're being asked to make at this time.

Specifically the PUC application really does ask the PUC directly to be an active participant in that FERC proceeding in supporting their application for cost recovery.

So let's review the projects very quickly. I have a bunch of summary information at the very back of the presentation on the individual filings that I'm not going to present in the interests of time. But let me just give you a feeling for these.

This is the first two segments. The first segment is to connect Antelope to Pardee; it's about 26 miles, $80 million. The idea here is to connect by 2006 200 megawatts of renewable resources that Edison's already well on the way in terms of system impact studies for.

Segment two is another network upgrade; this time between Antelope and Vincent. It's part of a two-part set of activities. Let me show you the next segment of it.

Segment three is to actually go from the Antelope station up to some substations that would augment and essentially replace some of the substations that are already up there but that are weakly connected to the Edison system, with higher voltage transmission lines. These lines are all being proposed at a lower voltage initially, with the possibility to be able to upgrade them as the resources develop.

I need to also point out these first two are clearly network upgrades, and they're interconnected to multiple points within the system. This is a radial upgrade, and hence one of the points for discussion as part of the justification for the location.

Looking very quickly at these filings, you know, on the surface there are really no inconsistencies among them in terms of what is being proposed physically, in terms of the justification that is being offered, in terms of the costs that are being proposed. And in terms of the objectives that Edison has in making these filings.

There's a lot more detail, of course, in the CPCN filings that's consistent with that type of filing in terms of the physical structures and what will be put in place in the ground. But, you know, from the first broad review there aren't inconsistencies among them.

We had a few observations that we'll just offer at this point. I think the key point to remember is that the resources that these facilities are being proposed to interconnect are in various stages of development. Interconnection agreements have not been signed with any of them, to my knowledge.

And so these plans are designed to be upgraded and changed, I believe, as a result of changing conditions with respect to the development of those renewable resources. So there's a lot of details to be worked out. If I go back a slide -- yeah -- there's a lot of details to be worked out on what exactly takes place up in this upper region depending upon how the renewables actually develop.

From a reliability perspective, clearly the new contingency that's introduced will be this radial line connecting about 700 megawatts to the system. That contingency would still be less from the control area standpoint of the loss of a single unit of Diablo or San Onofre.

As we heard this morning, you know, there are other issues that are outside the scope of Edison's application that speak to the deliverability of some of these resources outside the Edison service territory.

And then from our first review, really, that this type of planning, what is being proposed, the sizing, the need to build ahead, that does seem consistent with the expectation for the type of resource development that is being proposed at this time.

So, with that, let me conclude my remarks. And be available to answer questions. I apologize to the Commissioners and participants that I do need to leave shortly.

PRESIDING MEMBER GEESMAN: What time do you need to walk out?

MR. ETO: In about ten minutes.

PRESIDING MEMBER GEESMAN: Okay. I wanted to ask you, as it related to the Cal-ISO analysis of Palo Verde-Devers 2, one of the recommendations in your earlier report had been a longer period of analysis. What timeframe did the Cal-ISO attempt to cover?

MR. ETO: The California ISO's methodology consists of two snapshots, 2008, 2013. And our recommendations are actually twofold in this area. One is it's important to look at the year-to-year issues that it would affect some of these capacity expansion questions, instead of the two snapshots. As well as extending the period of analysis, and we would recommend eight to ten years. Sort of a continuous record over that period.

PRESIDING MEMBER GEESMAN: Yeah, I guess I continue to have lingering concerns as to whether even that will continue to understate the benefit side of the equation. As some of our reports have discussed, you're looking at facilities with 30- to 50-year lives, and I certainly acknowledge the difficulty, if not impossibility, of modeling a reasonable projection of grid conditions over that long a period of time.

But I think that needs to be explicitly recognized when we're making these cost/benefit calculations, because there does appear to be a methodologically driven understatement of the benefit side.

MR. ETO: I agree with you in a couple of different ways. One, I think you have these methodologies are very complicated, very time consuming, resource intensive, and that's what drives an analyst to move to single-year snapshot type of evaluations. And so it may be the case that these types of techniques in and of themselves are inappropriate for, you know, trying to run them for 20 years or 30 years at a time.

That said, I would certainly agree with you that considering those issues farther out in time is very important. It's part of the rationale behind looking at a social discount rate for considering some of these values.

And it may call for different types of methods; different types of techniques. I certainly am concerned about, you know, given the level of the -- the immense amount of information that goes into something like a team methodology, that you just try to expand that out to 30 years, I'm not sure how much value you add through --

PRESIDING MEMBER GEESMAN: Yeah, I don't --

MR. ETO: -- that --

(Parties speaking simultaneously.)

MR. ETO: -- uncertainties we're dealing with. That said, those uncertainties, I think, are very important to be cognizant of, and that there ought to be other approaches to begin to try to introduce those considerations into the planning process.

PRESIDING MEMBER GEESMAN: Well, I'm troubled that the temptation is to have a regulatory decision that imputes a level of precision to the outcome that is far beyond our capabilities to know. And yet I look at our historical record. I think one of your earliest reports indicated that, that many of these projects, if not all of them, seem to generate a lot more benefit over their operating lives than are ever calculated at the front end.

And I think our decisionmaking process needs to somehow be informed by that fact, and not place excess reliance on detailed quantitative methodologies that by their very nature don't encompass the full scope of the problem.

MR. ETO: Well, I had a professor in college who once said that you should never confuse the things you can count for the things that really count.

And I think, you know, we're dealing with these intangibles and these uncertainties, you know, it's not appropriate to ignore them; and it's also very important to recognize the limitations of the types of quantitative analysis that you can conduct. And they are very valuable, I don't want to understate the importance of quantitative analysis.

PRESIDING MEMBER GEESMAN: Thanks very

much.

MR. ETO: Other questions? Questions from the audience?

MR. BARTRIDGE: You need to identify yourself at the microphone.

MS. SCHILBERG: I'm Gayatri Schilberg with JBS Energy representing TURN, the ratepayer advocacy organization.

Just had a couple of questions on your D-PV-2 analysis. I know some of your early slides came from the ISO report, the team report, and for example, on your page 8, which is the first -- the analysis before you've included the strategic analysis.

Do you happen to know if the benefit/ cost ratio was calculated using like present value of revenue requirements? Or is it just that capital cost that you listed a few pages before?

In other words, does it include income taxes and property taxes --

MR. ETO: My understanding is that the ratepayer impact was a present value revenue requirements type of calculation. And that's the translation that goes into some of these levelized calculations.

It would be not appropriate to conclude those in the societal test.

MS. SCHILBERG: Although the levelized cost for the two are the same, so does that indicate that maybe --

MR. ETO: That would tend to indicate, if they were included in one that they are being included in the other. That's correct.

MS. SCHILBERG: Or their not in either. Okay, well, then my second question is relating that to the use of the 7 percent discount rate. Now, I think you said something about weighted cost of capital, but my understanding is the weighted cost of capital to be much closer to 9 percent at this point, wouldn't it, or --

MR. ETO: It's represented as being equal to the weighted average cost of capital in the report. I'm not going to make an independent assessment of what that weighted average capital --

MS. SCHILBERG: I see, --

MR. ETO: -- cost of capital is.

MS. SCHILBERG: So then, just for some clarity then, so your social discount rate, you're suggesting it's essentially two points less than the weighted cost of capital. Is that --

MR. ETO: That was the example that we've proposed -- that we've prepared for this illustration of the effect of using a lower discount rate to value those benefits.

MS. SCHILBERG: I mean would that be the kind of difference that you would find reasonable, or is that just --

MR. ETO: In the literature that I've reviewed I've seen it go from 2 to 5 percent. And I think 5 percent was chosen really as a conservative number to illustrate the impact of choosing a lower social discount rate.

There is a large environmental literature about how you would actually estimate the social discount rate. And a number of different factors can go into that.

The point being that it would be a different rate, and from all the work that I've seen, a much lower rate than it would be a weighted average cost of capital that a private firm would use.

MS. SCHILBERG: Yeah, that was my question. So you're saying two points or to five points lower than the weighted cost of capital.

MR. ETO: That's what appears in most of the academic literature I've seen.

MS. SCHILBERG: Okay, so then going to your slide 10, if you still have another moment or two. So I just wanted to talk about your points number 2 and 3.

Using the expected value for energy benefits -- well, the goal of including this insurance value. And that was, I think, one of the justifications for using the social discount rate, right?

MR. ETO: No. There are actually two separate recommendations. The social discount rate really refers to how you would value from a societal perspective future benefits of an expected value type, okay.

And then this point refers to the fact that what the ISO has actually done is somewhat of a -- they've done like 66 sensitivity cases. They've done sort of a scenario type of analysis looking at different types of assumptions.

And I think that there are ways you can extend scenario analysis using, as an example, Monte Carlo techniques, and actually develop something like a probability distribution for future outcomes.

And when you do that you can begin applying techniques that the insurance industry uses to set premiums as a way of looking what it's worth to you to guard against bad outcomes. And that's an area of methodological development that we're still working on for the PIER program at this time.

But it's a separate issue from the issue of the insurance value. The insurance value really is about protecting yourself against bad things happening.

MS. SCHILBERG: Right, and actually that's the one that I want to talk about. Insurance against bad things happening, because like as I've said on other occasions, we have insurance in many forms. Procuring 90 percent of our requirements in advance and having demand response goals. We have many other venues in which we are pursuing insurance.

So, how do you get only the incremental component that this transmission is going to provide? Because we already have all those other things in the pipeline, and if you don't calculate just incremental, we're risking double counting that insurance value.

MR. ETO: Sure. Well, I can answer kind of mechanically, but also maybe speak to the procedural issues.

Mechanically what you do is essentially do two analyses. One with the transmission, one without the transmission. You figure out what it would be worth to buy insurance premium under each of those scenarios to protect against the bad outcomes under the two scenarios. The difference in that price of the premium is the insurance value of that incremental addition.

Now, I think the other part of your question though speaks to, you know, implicitly we're treating other things, from you know, -- I don't know how explicit it is, as insurance. And to the extent that other things have insurance value, I think that should be considered.

I think what we've found from our review, looking historically, is there have been lots of instances where transmission has provided incredible benefits that were not anticipated at the time of construction, never anticipated, in fact. The fact that we have this record suggests that we ought to be thinking more aggressively about recognizing that possibility in the future.

And that's kind of what's motivating this thinking along the line of trying to capture insurance value.

MS. SCHILBERG: Yeah, I'm just worried that given that we already have all these other programs in place, had they been in place in the past when you, you know, in past history, maybe the unrecognized benefits wouldn't be as big as you're finding in your study.

In other words, the baseline has changed.

MR. ETO: Sure, I would say going forward the baseline ought to be consistent with, you know, the resource procurement policies of the state, as well. So I'm not suggesting that transmission insurance values is looked at independent of insurance value, or the baseline contribution of other resources in the portfolio.

MS. SCHILBERG: Yeah.

MR. ETO: So I'm not really speaking to the larger portfolio balancing issue, but given that you decide the transmission is what you want to do in this instance, that you ought to be recognizing all the benefits and values that it does bring in the context of the evaluation of its worth.

MS. SCHILBERG: And just a quick point on the environmental benefits. I think you kind of skimmed over the fact that it could go both ways. There could be negatives and positives, especially with respect to this line bringing coal-fired generation, for example.

And so would you like to expand on that a little bit in this context of this one.

MR. ETO: My comment was really that, you know, the ISO has begun to look at impacts on NOx. And that's a step in the right direction. And I would argue that there are other environmental impacts that should be considered, as well.

MS. SCHILBERG: Okay. Thank you.

PRESIDING MEMBER GEESMAN: Thanks, Gayatri. Sir.

MR. TOOLSON: My name's Eric Toolson; I'm with Pinnacle Energy. I don't speak for the ISO, but I am familiar with their study. And there's a couple points I thought I could clarify.

Appreciate Joe's presentation. One was on the economic life. The ISO assumed an economic life of a transmission line is 50 years. Of course, that creates the problem of how do you evaluate the benefits.

Originally they intended to evaluate the benefits in three years, 2008, 2013, 2018. 2018 was never completed. So they had 2013. At that point the philosophy was, and the philosophy I agree with, that if you tried to model the benefits out to 2030, '40 and '50 there'd be so much guess work that it wouldn't be worth the effort.

So instead, recognizing that the project has a 50-year life, you can take the benefits in 2013 and just extrapolate those. Now that has roughly the same level of accuracy as trying to do a detailed simulation.

In their report, if I recall correctly, they extrapolated that at five different real discount rates. So the decisionmaker, they're not saying I think it's going to escalate at a 1 percent real or anything like that. They're saying here's five potential outcomes; you can look at that and see how robust the decision is.

So, just a clarification. They did look at a 50-year life.

On the second part there's some questions on the discount rate. They used a weighted cost of capital. It was Edison's weighted cost of capital. That weighted cost of capital was about 10 percent in a nominal fashion and about 7 percent in a real fashion. So the 7 percent is a weighted cost of capital expressed without inflation.

And so those are the two points I wanted to make to clarify that.

PRESIDING MEMBER GEESMAN: And while we're throwing discount numbers around, my recollection is that the Energy Commission used either 3 or 3.5 real as a discount rate in evaluating our building and appliance standards.

And if I recall properly, NRDC was recommending that we use 2.5 percent real. So there is a range of opinion as to the appropriate social discount rate.

Other questions for Joe? Joe, thanks an awful lot.

MR. ETO: Thank you.

MS. GRAU: Next we have Peter Mackin with Navigant.

MR. MACKIN: Good afternoon,

Commissioners and members of the audience. Thank you for having me here.

I guess the first thing that I wanted to mention is that we just were recently informed that we had this task order to do this work. And Mark's not here now so I can't thank him; but I was going to thank him for inviting me to this presentation. I only found out two weeks ago I was going to be here. And so we haven't had a lot of opportunity to do -- make a lot of progress.

But what I wanted to do today was just give you, well, a status of what we've got; and also to give you some historical or some background information on a couple of the tasks that we're planning to undertake.

So, next slide. The first item I wanted to talk about was the reliability benefits of the economic transmission projects. And we're -- well, at this point we have not made any progress on this task. But one of the ideas or what we were planning to look at in this particular task is when you have a transmission project that has been determined, let's say, through the ISO STEP process, or however, that it's economic for the State of California, or economic for the WECC region to build this project.

Are there benefits that -- reliability benefits that aren't being captured in the evaluation that perhaps should be evaluated that would help, that would increase the benefits that you've seen. And they should be things that you ought to consider.

And an example of that might be a remedial action scheme, for example. Now, on the Midway-Vincent Path 26 upgrade, if you look at how that upgrade is being done, it's being done essentially through remedial action schemes. And I'd be referring to either the 3400 to 3700, or the 3700 to 4000 megawatt increase. Essentially the increase is being driven by increases in remedial action schemes.

So you're not building any new transmission. So you look at it from a perspective of reliability benefit to that project. The first glance at it would say probably there is no reliability benefit to increasing the transfer capability, at least on a transmission perspective.

Because now you're looking at higher flows on the same number of transmission facilities. And if you lose those transmission facilities, you have higher impacts on the remaining facilities, or you have the risk that your remedial action scheme will fail, and so your outage probability or loss of load probability has gone up.

So in that particular perspective for that particular project the reliability benefits may actually be negative. But being negative isn't a bad thing because you still meet your reliability criteria. So you're still -- it's still a good project; it's just that your reliability benefits are less than one.

Okay, and then the second item that I plan to talk about will be -- I'll give you a little bit of background on the transfer capability between Los Angeles Department of Water and Power and Southern California Edison. This is another task that we've been asked to look at. And what we're planning to do in this particular item is we'll be looking at the actual transmission capability, transfer capability between LADWP and SCE; and whether power transfers in actual system operation has been limited. And if it's been limited, was it limited by transmission transfer capability or was it limited by resource availability on either the Edison side or the LADWP side.

And then the third item will be to give you an update on the southern California transmission congestion. So this is the third item we've been asked to look at, and in this item what we're going to be looking at is basically the import capability into southern California. And historically, especially in 2003, 2004, there was a lot of congestion. And what we're going to be looking at in this particular item is, you know, what the congestion was; when it occurred; and why it occurred. And propose, possibly, depending on what caused it, propose solutions to mitigate it in the future.

Okay, so then the next slide -- we can skip that one, that's just sort of a placeholder. This particular diagram, I guess one thing I wanted to say about this is I don't know if anybody -- well, some of the older folks in the audience might remember when Ross Perot was running for president, and he had the shows. He bought time on tv and he had those PowerPoint slides.

Well, this is my version of the Ross Perot slide. And what this indicates is that you really should never let an engineer try to be a graphic artist.

(Laughter.)

MR. MACKIN: But the purpose of the slide is to show the four interconnections between the Southern California Edison transmission system and the Los Angeles Department of Water and Power. And on this diagram it may be kind of hard, I guess you can see it okay on the screen, they are indicated in blue.

And there's essentially four connections. There's a 115 kV connection at Inyo. And then there's the 230, 220 kV transformers at Sylmar. There's a 500 kV connection between Victorville and Lugo. And a 500 kV connection between McCullough and El Dorado in Nevada.

Okay, so the next slide. The Sylmar interconnection is known as WECC Path 41. In the WECC path rating catalogue it is number 41. And what it consists of currently is three 230 to 220 kV transformers at Sylmar.

Two of these transformers are rated -- they're the older transformers; they have ratings of 600 normal and 800 MVA emergency. And then the third transformer, which is new, is rated at 900 normal and 1156 emergency.

The nonsimultaneous rating of this particular path is 1600 megawatts in both the north-to-south and south-to-north directions. And it's limited because you've got three transformers in parallel. There aren't really any parallel path effects. You really only have to deal with the loss of one of the three transformers in the path. And if you lose the largest transformer, the remaining two transformers have an emergency rating of 1600 MVA. So that's the path rating.

And the capacity on this particular path is divided between Pacific Gas and Electric, Southern California Edison, SDG&E, CDWR, LADWP and three municipals in southern California.

I guess the reason the capacity on the path is divided between -- well, PG&E, why PG&E and SDG&E have a share of this path is initially before the DC converter upgrade, there was half of the, not quite half, but a part of the DC line terminated in the LADWP control area, and half -- or a portion of it terminated in Edison's control area.

And so in order for PG&E to get -- and San Diego to get their share of transfer transmission off the DC, they needed to have the capability to go over the Sylmar path to get to SCE.

Okay, next slide. The next path I wanted to talk about is the Victorville-Lugo path. And that is what's known as WECC Path 61. And that particular path, it consists of a single 500 kV line between Victorville and Lugo substation in SCE's territory.

It has a simultaneous rating of 2400 megawatts from Victorville to Lugo; and 900 megawatts from Lugo to Victorville. And the reason here for the limitation, this is the -- the line, itself, actually has a rating higher than 2400 megawatts, but it's limited because of outages on other facilities can then cause the flow on the Victorville/Lugo line to go up to its emergency rating.

And for the north-to-south direction, or from Victorville-to-Lugo direction, your contingency is loss of either Mojave/Lugo or the El Dorado/Lugo lines. And that can cause the flow, like I said, the flow then goes from the --

it was coming on the El Dorado-to-Lugo path; it ends up going up through the Lugo/McCullough tie, and down through L.A. through Victorville and into Southern California Edison, and it causes an overload. So that's the limiting contingency there.

For the south-to-north rating you have, it's limited by the transfer or the rating of the Inyo/Kern/Searles 115 kV line under N-0 conditions, which is actually L-0 conditions. And so you have to limit your flow to 900 megawatts. Because otherwise you will exceed the rating of the 115 line.

And for this particular path LADWP owns the line to the midpoint from Victorville, and Edison owns the line from the midpoint to Lugo. And, as I mentioned earlier, the rating is 2400 megawatts from Victorville to Lugo, but the actual capacity of the line is 3000 amps, which is, I believe, 2598 or something MVA. So it's got a higher actual capability, but it's limited due to other contingencies.

Okay, and then this nomogram, I'm not going to go into a huge amount of detail because it would probably bore everyone to death. But what I'm attempting to show here is that before the transformer was added, the third transformer was added on Path 41, there was a bit of a simultaneous interaction between Path 61 and Path 41, which you can see over in the right-hand corner of the black line where it has a sort of an angle dipped down.

Now that the third transformer has been added the nomogram has turned itself into a square which is essentially no nomogram, so there's no simultaneous interaction now between the Sylmar path and the Victorville/Lugo path.

Okay, next slide. And this nomogram here, this one is just to show another interaction between Path 61, which is again Vincent -- excuse me, Victorville/Lugo and the Vincent/Lugo lines. And in this particular instance, if the flow on the lines between Vincent and Lugo, there's two of them, if they get too high an outage of those two lines will then cause an overload on the Victorville/Lugo lines. So you have to limit the simultaneous flow on the two paths.

Okay, so then the next slide. And lastly, on Path 61 there's a dynamic nomogram which monitors the actual flows on four lines, the

El Dorado/Lugo, the Mojave/Lugo, Palo Verde/Devers and the Hassayampa/North Gila. And it monitors those flows such that a contingency on any of those four lines would not cause an overload of the Victorville/Lugo line, again, which would not cause it to go above 2600 MVA.

Okay, next slide. And then the last path that I wanted to address is the El Dorado/McCullough interconnection. And it's a whopping .6 mile long, 500 kV line between El Dorado and McCullough. And its rating, it's a steady state rating of 2598 MVA, or megawatts; and it's in either direction; and it's based on terminal equipment. So there's really no simultaneous interactions with other paths that would affect the rating of this path. It's just limited by the equipment at the terminals.

And then the next item is going to be, I want to talk a little bit about some congestion in southern California. What we've done here is we've gathered some data from the ISO looking at congestion, monthly congestion organized by branch group. And for this particular slide what we've looked at is all hours for the year 2003.

And we've looked at four, five, six

different paths. We looked at El Dorado, the El Dorado branch group; the Palo Verde branch group; Path 15; Path 26; the Mead branch group and Victorville.

And the two, well, the Path 26 branch group does lead into southern California. Path 15 really doesn't, but Path 15 can be interesting in some instances because of the relative magnitude of congestion on Path 15 versus the congestion on the paths into southern California.

And one thing to note here on this particular slide is that the green line is the Path 26 congestion. And the sort of magenta line is Palo Verde. You can see those are the two paths that seem to have the highest congestion in 2003.

And this is on a percentage basis, so this is a percentage of all hours that had congestion. So if you look at the peak there in May for Path 26, it looks like about 34 percent of all hours in May there was congestion on Path 26.

Okay, then the next slide. The next slide is the same information but now it's broken out by peak and offpeak. And the first slide here is to look at the peak hours. And what you can see from looking at this particular slide is that the Path 26 congestion appears to be pretty much a peak problem. Because if you compare that to the slide previous the shape of the curve looks pretty much the same. So you could gather that more than likely it's a peak congestion problem. And for Palo Verde it's also, it appears to be a peak congestion problem.

Okay, then the next slide is the offpeak hours. And the only interesting point to make on this slide, and this is probably something that we will be looking at as part of the work authorization that we have, is that there was some fairly large congestion on the Palo Verde path in December. And at this point I'm not sure why that happened. So we'll be doing some investigating and trying to figure out what caused that, and if there are any mitigation measures for it.

Okay, then the next slide is -- this is basically a load duration curve of congestion. So what we've got is the dollars per megawatt hour of congestion sorted by -- well, as percentage, sorted by magnitude. So, what you can see by looking at the curve is the area under the curve gives you a feel for how much congestion you had on the path.

It's not the total magnitude of the dollars of congestion because in this particular case what we're looking at is simply the dollars per megawatt hour. Where the actual congestion would be the dollar per megawatt hour times the actual rating of the path. And so if you look at this particular slide you can see that for 2003 it looks like Path 15 had the largest amount of congestion on a dollar per megawatt hour basis. And then that was followed by the Palo Verde branch group, and then the Path 15 branch group.

Okay, then the next slide. So now we're looking at the same information again, but now it's repeated for 2004. And one thing to note here for 2004 that's interesting, is that the Palo Verde congestion has gone up significantly. It's now as high as, in September, 45 percent of all hours -- well, not quite 45, but 44 percent of all hours in September were congested on the Palo Verde branch group.

And a lot of that could be due, you know, again, we need to -- we'll be doing some investigation to find out exactly why, but it's more than likely due to, you know, the addition of new generation in Arizona and the Mexico area is probably the cause for that. But we will find out. We will be doing some investigating to find out for sure.

And then the other thing to note is the Path 26 still has to be -- still seems to have some fairly significant congestion, but it appears to be a little bit lower than it was in 2003.

And one thing that I wanted to point out, too, if you'll notice. We talked earlier about the Victorville/Lugo path, and if you look on this slide, and you also then refer back to the 2003 slide, you'll notice that the congestion on the Victorville path was pretty much zero for every month. So it doesn't appear from this information that the Victorville/Lugo path was congested very often.

And then the next slide. Are we on peak? Good. For this particular slide, again you can see, if you compare the slide to the previous slide, that the Palo Verde and the Path 26 congestion again appears to be mostly an onpeak problem, because the onpeak hours look very similar to the offpeak.

And one other thing, too, to point out

is that, and it's clearer on this slide than it was on the 2003 slide, is that the El Dorado congestion, which is the blue line, the dark blue line, it tends to follow the Palo Verde congestion because the paths are parallel. So if the Palo Verde branch group is going to be congested, then you may get transfers, people try to bring power in on the El Dorado branch group if they have the rights for that.

And then you'll see higher congestion -- it tends to follow, although it's not nearly as high, it does when there's really high congestion on Palo Verde, you'll see some high congestion on El Dorado also.

Then the next slide, this one is 2004 again. This is offpeak. And what's interesting here is that you can see on Path 15, which is the yellow line, this one sort of follows the typical, what you would typically expect to see for Path 15 because in the late summer and fall, winter, you have high congestion on Path 15, which is when energy's being returned from the southwest to the northwest. And you also have lighter loads in California than the flows return energy to the northwest seems to go up.

One thing that is interesting. If you'll note in November and December then the Path 15 congestion tended to go down. And I believe that was all due to the fact that in November you had the Path 15 upgrade go into service. So the rating went from 3950 to 5400. So that helped quite a bit in December.

And then also the Palo Verde branch group, there was high congestion there in the spring. And also in the summer. And, again, this offpeak congestion, this is something that we would have to look into because this seems kind of unusual. But we'll be looking into that as part of this project to see what caused that high congestion.

And then the last slide is again the load duration curve of the hourly congestion for 2004. And here now you can see that we had a little flip-flop in the relative magnitude of Palo Verde branch group now is much higher than the other, than the Path 26 was in 2003.

And then below the Palo Verde branch group then you have the -- I'm trying to get the colors matched; I can't be sure which one is next, but Path 15 then is below Palo Verde. So it looks like, actually it looks like Mead is following below the Palo Verde branch group as far as congestion.

So that basically concludes the presentation for me. Does anyone have any questions on what I've presented so far? Anybody awake?

(Laughter.)

MR. MACKIN: Okay.

MS. GRAU: Okay. And our final speaker this afternoon is Eric Toolson with Pinnacle Consulting.

MR. TOOLSON: Okay, it's a pleasure to be here today. I was asked to talk a little bit on potential transmission and resource valuation criteria. And I think the impetus for that is, it's important for the state if they're going to be involved in statewide transmission and generation plans to have a common set of criteria that they can evaluate it, whether it's a single project or a whole resource strategy or scenario.

And so that's the assignment I have is to develop, recommend some criteria that I think would be meaningful and pick up the perspectives and priorities of a pretty diverse group of stakeholders.

And so I'll go through where I am in the process; what kind of input I've received; and what I intend to do after this.

Why are we developing the process? Well, I mentioned that a little bit before. You can look at resource scenarios and resource plans, and if you have a good set of evaluation criteria and evaluation matrix, then you can make decisions on that. And even though the criteria may not be directly comparable, some may be quantified, some may be qualified, you can look at those and decide that. And you can decide where do I want to be in 2015, 2020. What kind of infrastructure do I want for the state. What sort of things do I want to promote.

And by evaluating those and selecting a resource strategy, you can say these are the policies I want to implement at the state level. Or as mentioned here, you can look at it for even specific resource options at the utility or a smaller different level than that. And so that's why we're developing these criteria. And that's, you know, where it's important.

Okay, what's the process for that? We

thought it was important not for me to just do this, and I've been in resource planning for about 25 years, and I have some ideas on what I think evaluation criteria should be. But I wanted to step back from that and survey a pretty diverse group of stakeholders in California.

And so that was the first part, is to survey them. And this might be an appropriate time to mention I have my PowerPoint presentation. Some of you may not have noticed, there's a table next to that presentation. It's an Excel table that's not very pretty. But that records the information I've received so far. I'm not going to talk about it, but if you're interested in getting into the details and understanding where this criteria came from, most of it's logged there.

So the first thing is to go out and interview the stakeholders. And what I wanted to do is get a fair understanding of what they meant, whether I thought it was a credible criterion or not. And so we interviewed a lot of people. We interviewed people that are consumers, TURN, industrial groups; we interviewed all three of the IOUs. We interviewed a number of the municipal utilities. We've interviewed environmental groups, NRDC, CEERT and others. We've interviewed people or intend to interview people as diverse as Save Riverside County.

And from that I'm getting criteria that I'm going to represent in this portion of the presentation. The next step after that, once I continue and complete the survey, is to make a recommendation of maybe five or six criteria I think would be important in evaluating alternative resource scenarios, or evaluating transmission versus generation.

Now, people ask me, well, what's going to happen at that point. I don't know. The CEC will receive that and they can accept that or not. And they'll prepare it and include it in their IEPR. But at some point we need to develop an evaluation matrix and that's the purpose of what I'm doing.

Okay, and I mentioned before some of the stakeholders surveyed. You'll also notice on this table, if you happen to pick it up, the final column of that lists where some of those sources come from. Originally I wasn't going to mention that; I was going to keep it anonymous. But I think it's important to have that down because some criteria you'll understand a lot better once you see the entity that's recommending it.

So, for instance, market efficiency comes from the ISO. Well, that's one of their missions and so they propose a test for market efficiency. So I left those names in there.

You'll also see that there's a couple of columns, one is proposed criteria and the other is a possible measurement. You might have the greatest criteria in the world but if there's no way to measure it subjectively or quantitatively, then it has less value to us. So I put those in there. Anyway, that's the group of people that we interviewed. We've talked to about 20 people so far. When I say we, that's myself. And I have about ten more interviews to do.

Okay, let me go over some background on this. As I mentioned I'm a resource planner. And some people might think, you know, this is nothing new here; this has been done for 20-plus years. We've done integrated resource planning.

SMUD, ten years ago, when they came out with the 1990 resource plan had what they called a multi-attribute evaluation matrix. So they looked at things like cost. They also looked at environmental issues. They looked at how much DSM was in there; how much renewable. They looked at things like local economics, or local employment. They also looked at something called public acceptance.

So even as late as 10 to 15 years ago they have been using evaluation matrices with some things that can be quantified and some things that cannot, to determine resource portfolios.

So people say well, what are you doing with this now; this has all been done. Sure, a lot of the principles have been done, but there's a lot of new criteria you see now with RFOs and with other statewide planning that weren't considered ten years ago.

Ten years ago there was no formal way and accepted way to measure risk in a resource plan. As a matter of fact, you'd do some sensitivities, high gas, high load growth, you'd get an idea what happens. Nobody quantified it.

So there are some new things that we're considering.

Okay. Things that are traditional that haven't changed much. We've always worried about reliability; reliability standards have always been in there. Everybody's looked at some form of least cost, whether it's rates, whether it's ratepayer costs; that's pretty standard.

People have looked at rate impacts for a long time. Airborne emissions. We had the capability ten years ago of modeling some airborne emissions. Now that wasn't as well developed as it is now, but that was certainly a concern ten years ago.

Operational flexibility. People would be running chronological simulation models and they would understand the impacts of the operational flexibility on the overall cost. And so in that way it was also included in public acceptance.

Let's talk about some of the criteria. Again, these are all criteria that have been suggested to me that are newer. Risk quantification. As I mentioned we didn't do that ten years ago. Portfolio fit, that's a big term in all the three IOUs' RFOs. How does it fit the portfolio. That's a new concept.

Reliability payments. Before you had reliability impacts, but you didn't have the

California ISO and you didn't have reliability payments like RMR and some of the other ones.

Market efficiency. The utilities didn't worry about market efficiency, they just worried about the cost to buy power. If the cost was less to buy power that's how the California/Oregon Transmission Project was justified. That's an economic project that was justified simply on the price of power from the northwest and the diversity from the northwest to California.

Okay, but market efficiency where you're looking -- and this was mentioned before as a strategic benefit for transmission -- when you're looking at the price in the market compared to the underlying cost, that's a measurement that's important. That's something that the ISO tracks and evaluates. And it may be something that's important from the state level.

Again, I'm proposing all of these at the state level, not at the utility level.

Seamless markets is important with RTOs. How do you measure seamless markets. Fossil fuel dependency. Fuel diversity was looked at a little bit, but now it's much more important both from a risk standpoint as well as just policy consideration.

Environmental justice is a term that none of us heard about ten years ago. And so that's a new concept. And I'll talk a little bit about that. And CO2 regulatory risk.

So you can see where a lot of these criteria are similar to the ones that we've had in the past. That doesn't make them invalid. It means they're time tested, and some of those are very important.

In addition, we've had some new twists and turns on that, and some entirely new criteria.

Okay, instead of using this as an exercise to understand how much DSM we should have in the portfolio, how much renewables, at this point we're saying there's some minimum requirements. No matter what resource portfolio you come up with, there's some requirements.

And these are the requirements that we're not going to evaluate and we wouldn't intend this criteria to evaluate. These are the things we accept. And when we look at different resource scenarios all of them will meet these very criteria that the state has already set in various forums.

Now, I've categorized them, -- you'll see on that table, although it's not very clear, all the comments I've received -- into four categories. Okay. Reliability. Least cost. Risk and environmental. Everything that's suggested to me I've put in one of those four categories.

Some of them, like CO2 regulatory risk, can fit in both risk and environmental. But I've put them in one of those four categories. And I'll go over those a little bit right now. These are all stakeholder-suggested reliability criteria. Remember, at this point I'm just trying to do a fair and accurate representation of what people think should be included in our criteria.

Unserved energy is one. Reliability payments is another. Okay, so as we do comparable studies with scenarios we can look at unserved energy. And I won't go into all the issues involved with these because that will be in a later report.

And reliability payments. Recognize that the California ISO in the team report attempted to understand the reliability payments with both the RMR and the minimum load cost compensation, and tried to understand how that transmission line might reduce those payments.

Okay. Least cost criteria that were suggested. A lot of ways of understanding least cost, present value, different perspectives as Joe talked about before.

The interesting thing is that if you look at the evolution of these simulations, they've gone from cost base, marginal cost, which everybody did ten years ago, to bid base, where you try to understand the market and put a bid in, whether it's a static bid that doesn't change, or dynamic bid like the California ISO tried to do, where it would change hourly depending on system parameters, reserves, pivotal players, so on.

And then eventually evolved to where you're doing an expected value. In other words, you're taking the probability times the outcome in a number of cases and computing the expected value.

Ratepayer impact is still important. Market valuation is important for a project. I don't know if it's as meaningful for a scenario. But certainly in the RFOs each of those utilities have a market valuation. What's the value of this resource in the market as we project it compared to the cost.

And the inclusion of environmental costs. That primarily is limited to airborne emissions. I don't know of a good way to include other environmental impacts at this time. And so they'd be qualitatively described.

Okay. And a lot of those were fairly traditional. Here's some of the newer ones. The California ISO has what they call a modified test. They're worried about market power, market efficiencies. The modified tests takes out generator profits from uncompetitive conditions.

Market efficiency. Again, the ISO and the state and others are concerned about that. Market efficiency could just be defined as what is the ultimate price in the market compared to what the underlying marginal costs would be.

Seamless markets. If we have seamless markets how would we compare one scenario to another. If one fostered seamless markets more than the other did, perhaps they'd be represented in the total imports and exports.

Another criteria that's important for the generators and for several other entities, is do you have a market that's robust and will support sustainable generation. It doesn't do us much good to have a really low market price if nobody's building energy plants, if no infrastructure is being built. So is it sustainable? Can generators build generation in that market, and will it be a healthy, competitive market, not just for short term, but also for a long time in the future.

Portfolio fit is what the utilities are looking at now as they look to new resources. How well does it fit into my portfolio. My take on that is the portfolio fit is important for what they're doing, but for when you look at long-term resource scenarios, you can do a lot of things to fit the resources around wind and other things like that. So, you know, there's a couple ways to look at, but portfolio fit was suggested.

Some of the risks suggested criteria, and the first three are just different ways to get at the same thing. If you're doing a distribution of outcomes you can compute an expected cost, and you can also look at the worst cases. And you can describe those worst cases as maybe the average of the ten worst, as maybe a cash flow risk measurement, a deviation.

But somehow understanding risk, you know, risk is big these days. And it should be because of all the volatility in the markets; whereas 1990 it wasn't so important. So risk is important and I add at least four different suggestions on how you might get a handle on it.

Also important is project, credit, counter party, technology risks. If you had a future built on tidal machines that might be great for renewable, but it might present more of a technology risk than you're ready to accept.

A lot of these are qualitative, still. You know, we don't know really how to come up with a quantitative index for technology risk.

CO2 regulatory risk. As I understand it the CPUC has instructed the utilities to include CO2 emission costs and given you a range to do that. As Joe said, the ISO was only able to include NOx in their particular risk profile, and CO2 was mentioned by a number of people including environmental groups.

Resource diversity. I think everybody would agree we want resource diversity. A lot of ways to describe it. The way that was put forth by NRDC is hey, just give me a pie chart. Just show me the kind of resources that are in that pie chart. Prepare that for every resource scenario you're doing and that would give me a good handle on do we have some resource diversity issues or not, of what's there and might be evaluated more than others.

Same thing with resource flexibility. You know, for instance, if you're to commit to a 2000 megawatt nuclear plant today, that would have tremendous capital expenses that are not flexible.

On the other hand, if you're committing to a transmission line today, you might find that your cash curve is very gradual as you go through the permitting. And it offers significant flexibility. And by flexibility I'm thinking more cash flow flexibility and financial impact.

Okay, this is just an example of one of the ways to quantify risk. This, again, was out of the California ISO team report. And this is a histogram. And if you look on the right-hand side it's probability. And then you get those bins or bars across that. That sums to 100 percent. So on this particular study there was approximately a 16 percent probability that the benefits would be between negative-5 and zero.

You might ask yourself how can a transmission line ever have negative benefits. The important thing to realize, this is for the participant here. And the participant is defined as the consumer, generator and transmission owner.

If we build, and let's just take a simple example, the generator -- if we build a large line, say Palo Verde-Devers, the California generator may not benefit from that. It may have a negative impact. But overall the project may still be feasible.

And so you can look at that. You can say, okay, the probable cost range might be between 10 and 20 million, and that's my distribution. Now, it's important to know that versus say a project that had 100 percent of its benefits in the $10- to 20 million range. This would be a risk issue that you'd want to take into consideration. So that's one way of quantifying it.

Environmental criteria. Some of the things that were suggested, more robust representation, airborne emissions, CO2, NOx, maybe some particulate. Certainly that can all be included in the modeling today. Price data is difficult to get at, but it can be estimated and you can do sensitivity studies on it if it's important.

CO2 regulatory risks from $8 to $25 a ton is a big risk, okay. And it can sway your results considerably.

Some entities are interested in have you got an amount of renewables greater than what's mandated. And they wanted to see that. And, in fact, I believe the CEC, in their request to utilities, has asked for a renewable case in which there's an accelerated development or something greater than 20 percent.

This next one's interesting. This was actually presented to me by LADWP. And they say one of the priorities for them, as a city, is to maximize the use of their existing transmission right-of-way. It's just a policy; it's written down. You use that existing right-of-way before you go to new right-of-way. And so people find that important. And right-of-way is just not, you know, the amount of miles of right-of-way, but somehow the visual and environmental impact. And that could probably be developed further from that.

New transmission line, anyway. Fossil fuel dependency. We talked about that. That's important. Environmental consideration.

Environmental justice assessment. Are you familiar with that term? You know, are we building our plants in economically disadvantages areas, and how would we ever get a handle on that. Well, I have an example of that that shows you one way that we can start thinking about that.

Once-through water cooling. NRDC. This isn't something that I had thought much about. But apparently this is a big issue. You know, water cooling. How much water does it require? Is it on the coast? Are there thermal pollution impacts? Those are other criteria that were suggested.

We look at this example. This is just something I came up with, but on the other hand if I want to look at environmental impact I'm interested in two things. Where our project's being built, and you know, is it primarily in disadvantaged areas.

So this is a 3-D graph here. And you can see that I've taken all the zip codes in

California, and there's about 3000 different zip codes in California. You'd never imagine there are 3000 till you did this study. But there's 3000 of those.

And so I've categorized those in five different bins. Now they're not the same number in each of the bins, and there's a slide at the end that shows what they are.

But roughly we're trying to say okay, you know, if you're in bin number 1, for instance, on income, you're the lowest income and your per capita income might be between zero and 20. I don't recall. And if you're in 5, then you live in Beverly Hills or something.

So if you can look through those lines and visualize -- I'm just going to step over here for a minute -- you visualize on the second income level, first of all, at the low income level we don't see any generation at all. And what I've done here is I've looked at all the plants that the CEC, on their scorecard, whatever they call it, are either operational or are in planning and have certificates. There's a criteria that I'm using.

But you can see under 2 there's a fair

amount of resources being built in that income area. Three isn't as much. Four isn't as much. And 5 isn't at all.

Well, that doesn't tell you the whole picture, of course. If you're building in a low income area and it has a very small population that might be more acceptable. And so we put in population there, as well, for you to evaluate.

You can see in number 2 it's kind of independent of the population. And so I don't want you to draw any conclusions from this. What I do want you to consider is that there may be a way to get a handle or an arm or some assessment in future resource plans where you're siting these in terms of an environmental justice type index.

Okay. Any questions?

PRESIDING MEMBER GEESMAN: I've got a couple.

MR. TOOLSON: Please.

PRESIDING MEMBER GEESMAN: On the diversity of resources I spent 19 years in the capital markets before coming here and heard diversified portfolio as a drumbeat. I focused on the bond side, but obviously there's a great deal of work that's been done on diversified equity portfolios.

MR. TOOLSON: Um-hum.

PRESIDING MEMBER GEESMAN: Is there a similar portfolio theory that either has been developed or could be developed with respect to electricity resources?

MR. TOOLSON: Let me give you my understanding of that, and perhaps others in the audience can comment on it, as well.

As we look at diversified portfolios and we try to understand the value of that, we can run a lot of different scenarios, whether they're Monte Carlo or not. And we can treat as stochastic variables some of those parameters that are important, like fuel, CO2, regulatory commissions.

When you're through you end up with a distribution of costs like I showed you in the histogram. You can compare those, and that starts to give you some value on the fuel side, okay.

But on the resource side we're not treating resources as an uncertain variable. So we're not picking that up. But we know it's important. So, instead of just ignoring it, the NRDC and others suggest at least represent it in a pie chart.

I know more diversity is better. I'm not able to put a dollar value on it right now. We can put a dollar value on the fuel side. We can put a dollar value on the hydro side. But not on the technology side, or, you know, the type of resources.

Any other thoughts on that out there? Okay.

MR. CAUCHOIS: Well, you know, in 1980 we --

PRESIDING MEMBER GEESMAN: Come on up, Scott.

MR. CAUCHOIS: A long time ago when I was at the CEC we did some -- following up the work of EDF we did some scenarios and looked at sort of the conventional utility portfolio and a renewable portfolio.

And, you know, you can measure side-by-side the risk, so we measured financial risk and payoff. And concluded actually that a diversified portfolio was less risky; it also happened to actually have a higher payoff because utilities at the time were moving from commitments to nuclear plants to additional commitments to coal plants.

So they had lots of eggs in a couple of big capital baskets.

So there are lots of things like that that have been done and shown that a diversified resource portfolio can both pay off, but it also, even at the same ratepayer effect, it could have lower risk.

PRESIDING MEMBER GEESMAN: Yeah, I would be interested in having submitted to our record any reasonably current research that's been done in that area.

And I guess I'm motivated by a couple of different things. I see some potential sources of generation possibly falling out of our mix, coal being one of them, with the potential demise of the Mojave plant.

But I also see us bumping up against some ceiling, doesn't exist yet, as it relates to natural gas dependency. And rather than deal with those questions qualitatively, if there's some analytical framework that could be constructed, or work that's been done elsewhere, I think it might be beneficial to us.

The second question is in the best fit category. Is there a rigorous analytical methodology to define that? Or is that, I know it when I see it?

MR. TOOLSON: Let me give you the perspective I have, and then -- this is from talking to various IOUS, and if there are any individuals here that are more familiar with it, they can comment.

Particularly in talking to PG&E it is quantified. Now, this isn't a standard test that you'll find in the text book. They'll look at it; they'll look at their profile; they'll look at hourly, you know, my surplus or deficit in that. And they have some type of weighting formula.

And so it can be measured in that way to the degree that you feel that that formula has credibility.

My only concern is if I'm looking at a transmission project that's 50 years, or generation project that's 30, these issues of where they're long and short make sense for the next few years. But after five or ten years, you know, they're not that meaningful to me.

And if the effect of those is that they're impacting wind and other resources I think we need to take a second look at what that is telling us, and whether that's really a valid perspective in the long run.

Because you can do a lot of things with new resources, and to say I'm locked into this contract and I'll always be locked into this baseload contract, I think that's an over-simplification.

PRESIDING MEMBER GEESMAN: Thank you.

MR. TOOLSON: Any other questions? Please.

DR. BROWN: Merwin Brown, Director of the PIER Transmission Research Program.

In your survey did you ever encounter anyone that raised the subject of security from the point of view of sort of a coordinated attack on the grid, whether --

MR. TOOLSON: That's an interesting question.

DR. BROWN: Yeah, whether it be from a terrorist or a major fire or maybe an earthquake, I don't know.

MR. TOOLSON: Right. Nobody really brought that up, but I read a paper from BPA the other day and they say that's a criteria as -- new transmission planning. You know, what's the impact, what's the potential impact of severity of that, you know, potential to do that.

And so I'm going to include that as a criteria. I don't have a good way to get a handle around that or measure it. And I'm going to talk to the fellow at BPA. But that was off my radar screen until earlier this week. And it came up, and I'm sure it's a big deal for government-related entities, federal government.

And that might even be on the table, although it wasn't in the presentation. Yeah, actually it's the third one under reliability. I got it there. The criteria would be something like minimize likelihood and consequences of terrorist threats to power systems.

Okay, so where I am now, I'm going to complete my interviews. And hopefully that represents a fair segment of the population. And I can say these are important criteria.

And I'll review that; I'll review which ones are easier to measure, which ones aren't. And then I'll say here are five of them that I think ought to be considered as we go forward.

And at that point, you know, people will come to their own decision or not. But, at least we'll have a start and a suggested matrix so that as we evaluate a heavy renewable resource, allowing generation in Mexico to continue, all these issues.

I don't have a position on them; I just want to see how they stack up with the criteria people think are important.

And that will be used by the decisionmaker. And so we're not suggesting a weighting. Some utilities have done a weighting. They'll say flexibility or portfolio fit is 20 percent of the grade. You know, that's all up to the decisionmaker.

But we're saying this we think is relevant information to the decisionmaker to evaluate these different portfolios and implement policies from them.

Okay. Any other questions? Thank you.

MS. GRAU: This concludes all the formal presentations for this afternoon.

Next on the agenda is any open discussion if we have any further comments anybody here in the room would like to make. And I don't believe, Clare, we don't have anyone on the phone who has a question. Okay.

Does anybody else have anything? Yes.

MR. HARRIS: Thank you, Judy. Commissioners and Mr. Smith and Ms. Jones, my name is Jeff Harris. I'm here on behalf of 3M Corporation, and specifically the 3M Composite Conductor Program.

3M brand has developed a new conductor that's known a the aluminum conductor composite reinforced, or the ACCR. In coordination with, I guess, various federal and private entities it developed the ACCR which can increase transmission capacity as much as 1.5 to 3 times greater than conventional conductors for the same amount of sag.

The use of this conductor within existing rights-of-way allows for significant improvements in transmission capability without having to replace towers and do some other things like that that can be quite expensive and environmentally damaging.

The product is light weight; it has a low thermal expansion; excellent fatigue resistance; and a high stiffness. And is also corrosion resistance.

The benefits include, as I said,

increased ampacity. There's environmental benefits from reconductoring, not having to modify towers. Visual impacts are usually about the same if you don't have to do those additional towers, or significant modification of towers.

The conductor is being put into commercial application right now with Excel Energy in Minnesota. There's a lot of information, and I'll provide some written comments with that detailed information.

I wanted to bring this to your attention because we are, number one, going to take advantage of the opportunity to file some comments to get the conductor into your process.

I also want to emphasize that we don't see the conductor as a replacement at all for what you're doing. It should be another tool that you have for your consideration.

So, again, let me stress, it's not an alternative to looking at new corridors. It's not an alternative to the work that goes forward.

I think, though, it can be a very good bridge in the short run to deal with congested paths. And in the long run, as well, for being another tool in the arsenal that we all have to keep the system robust.

And so I welcome the opportunity to answer any questions. And thank you for your time.

PRESIDING MEMBER GEESMAN: Thank you very much, Jeff. I've been briefed by 3M on that product, and I think it has some interesting prospects. In fact, I'd encourage it to some of your generator clients for consideration in their gen ties.

MR. HARRIS: Thank you.

PRESIDING MEMBER GEESMAN: Any other comments?

Okay, I want to thank everybody for participating, both today and in our earlier workshops. We've got an aggressive schedule, but there'll be several additional opportunities for public input.

And I think as we move into the summer our staff work products will take on a little clearer profile and hopefully they'll elicit quite a bit of good feedback.

Thank you very much.

MS. GRAU: May I say just one more thing really quickly. If you do have any written comments you would like to make, we'd like them by June 2nd. Thank you.

(Whereupon, at 2:53 p.m., the workshop was adjourned.)

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CERTIFICATE OF REPORTER

I, CHRISTOPHER LOVERRO, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Workshop; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said workshop, nor in any way interested in outcome of said workshop.

IN WITNESS WHEREOF, I have hereunto set my hand this 22nd day of May, 2005